CALIFORNIA
ENERGY
COMMISSION

MARKET CLEARING PRICES UNDER ALTERNATIVE RESOURCE SCENARIOS

2000 —— 2010

STAFF REPORT

Technical Report to
California Energy
Outlook 2000
Docket #99-CEO-1

FEBRUARY 2000
P200-00-004

STATE OF CALIFORNIA 1975 2000 ENERGY COMMISSION

Gray Davis, *Governor*

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Richard Grix,
Principal Author

Karen Griffin,
Manager

ELECTRICITY
ANALYSIS
OFFICE

H. Daniel Nix,
Deputy Director

ENERGY
INFORMATION
& ANALYSIS
DIVISION

Steve Larson,
Executive Director

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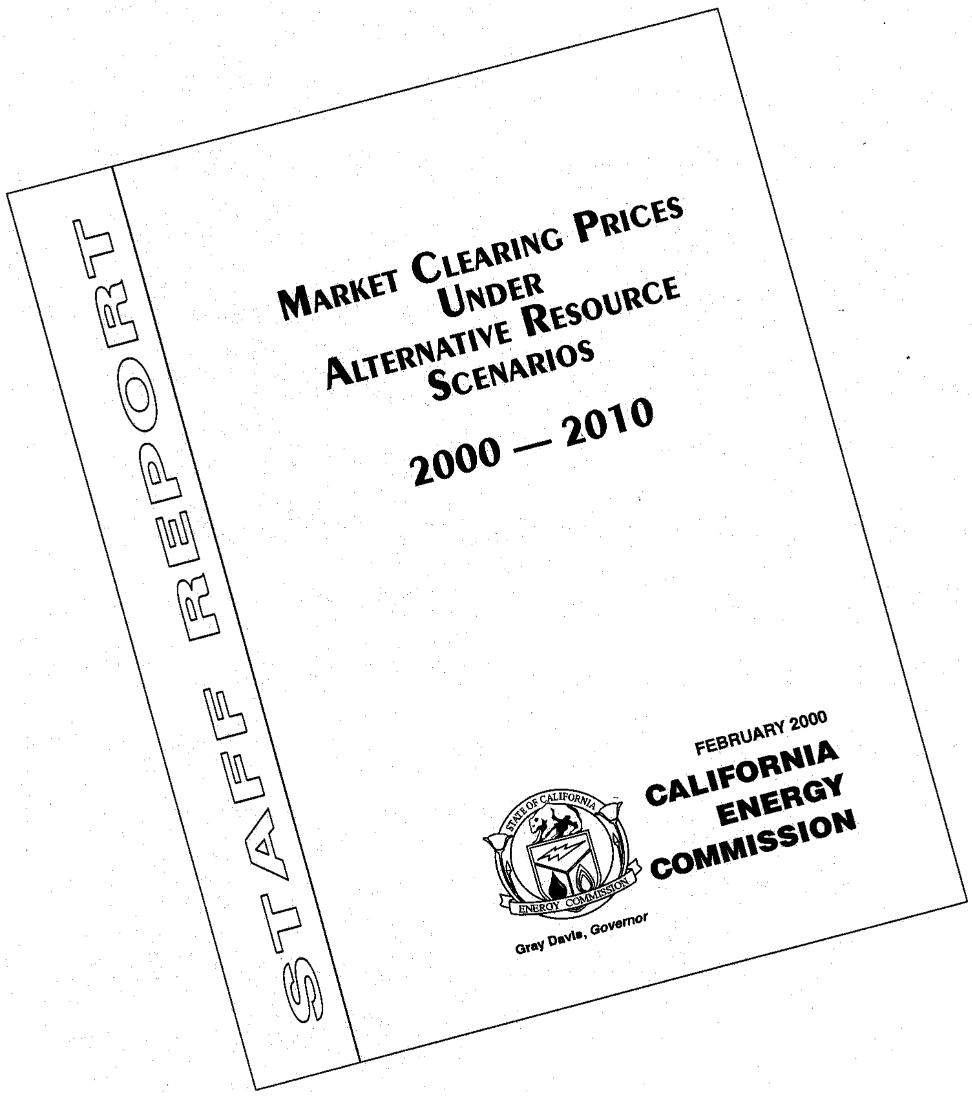

CALIFORNIA ENERGY COMMISSION

Richard Grix, *Principal Author*
Karen Griffin, *Manager*

ELECTRICITY ANALYSIS OFFICE

H. Daniel Nix

ENERGY INFORMATION
& ANALYSIS DIVISION

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Acknowledgments

Principal Authors and Multisym™ Modelers
Electricity Analysis Office
Angela Tanghetti
David Vidaver
Richard Grix

Contributors
Electricity Analysis Office
Denny Brown
Jerry Green
Joel Klein
Steve Layman
Ruben Tavares
Connie Leni
Bob Grow

Demand Analysis Office
Richard Rohrer

Fuel Resources Office
Bill Wood
Jairam Gopal

Electricity Analysis Office Manager: Karen Griffin
Demand Analysis Office Manager: Thom Kelly
Fuel Resources Office Manager: Gerry Bemis
Energy Information & Analysis Division Deputy Director: Daniel Nix

Executive Summary

In this report, the California Energy Commission staff evaluates the impact of two alternative resource development scenarios on market clearing prices for electricity purchased in California's wholesale market for the years 2000 through 2010. One resource scenario reflects rapid development of many currently announced projects and the other a more cautious rate of resource development driven by energy prices. Staff found that if eleven large power plants are put into service between 2001 and 2003, there would be more generation available than load growth requires over most of the ensuing decade. With this excess generation competing in the market, energy prices would decline below what is estimated as necessary to fund new generation. Developers are unlikely to build generation when the prospects for making a profit are so bleak. To proceed on the rapid development scenario, they would need to have alternative income sources, a significantly cheaper facility (or financing), or a perspective that some aspect of the future market is likely to be different from what is assumed in the staff's analysis.

The staff's forecasts of market clearing prices for these two scenarios for all years in the forecast period are based on the results from a regional market model. The approach attempts to capture the independent nature of resource development decisions. It is based on specific assumptions about the timing and quantity of new resource additions and provides useful insight as to how electricity prices in the competitive market would respond to an influx of new supply.

In developing the scenarios, the staff first evaluated over 40 proposed power plant projects for their likelihood of being built in California within the 2000 – 2010 time frame. This evaluation considered the potential for interzonal and intrazonal transmission congestion, natural gas availability, possible difficulty in mitigating environmental impact as well as the likelihood of local opposition. Based on these factors, the staff identified 19 plants, representing 9,186 MW, to include in the scenarios. Another 157 MW of capacity from new renewable energy projects were assumed to be built in the forecast period for a total of 9,343 MW of new capacity. For scale, this is approximately 14 percent of today's California capacity.

The rapid development scenario has 2,840 MW of capacity being added in 2002 and another 6,398 MW in 2003. The remaining additions involve one replacement/repowering of capacity in 2006 and another in 2008 for net additions of 104 MW. This rapid development leads to electricity wholesale prices dropping from a 2001 high of $30.3/MWh to a low of 21.9 $/MWh by 2003 (constant dollars). Market clearing prices are low until 2009 when they recover to current levels.

The cautious development scenario spreads out, in time, the development of the same projects included in the rapid development scenario. The same capacity is added in 2002, but only 1,819 MW are built in 2003. Eight projects that were added under the rapid development scenario in 2003 are deferred. This cautious development leads to prices dropping only to $23.7/MWh in 2003 and hovering about $2/MWh higher than the rapid development prices through the middle of the decade.

As a general guideline for adding new capacity, the staff used a reserve margin of 7 percent as an indicator of when to add plants that would be cost-effective to their owners. Planning reserve margins historically have been in the 15-20 percent range. The planning margin was intended to ensure that sufficient generation capacity existed at the time of the peak demand to cover supply and demand contingencies, and still meet minimum operating reserve requirements. If new load growth caused planning margins to drop to the 7 percent level, staff believed that prices would rise sufficiently to attract new entry. Our market simulations showed that this assumption may not be valid.

Overall, the staff believes that reserves will be lower in a competitive market as compared to a regulated market because of economic pressure to use resources more efficiently. Factors contributing to this include the following:

- A greater reliance on load diversity among regions in the West and an increase in regional transfers of electricity,

- Improved plant availability during peak demand hours which in large part determine whether a generator will make a profit for the year, and

- Greater demand-side responsiveness to high prices during the peak.

Because the staff is using a regional market model that simulates the loads and resources of the entire region encompassed by the Western Systems Coordinating Council (WSCC), it was also necessary to make certain assumptions about new additions outside of California. Of the 26,309 MW of new generation proposed for the WSCC outside of California, 7,173 MW were judged to have a high probability of being built because they were already under construction or had received all necessary regulatory approval. This amount of new capacity, however, was not enough to maintain the reliability of certain subregions of the WSCC outside of California. Staff added capacity to a subregion outside of California if its planning reserves fell below 6 percent. The staff, however, let reserves in some subregions drop below 6 percent in recognition that these areas have historically met peak demand by relying heavily on purchases from other regions.

The resulting average annual MCPs from the staff's two scenarios were compared to the annual average revenue requirement of a new market entrant. This comparison provides a useful measure when, how much, and how consistently, new entry is likely to be attracted to the California market in the next decade. Based on a fixed cost revenue requirement of $97/kW-year for a combined cycle plant and $72/kW-year for a combustion turbine and variable costs of $19/MWh and $26/MWh respectively, the market simulations indicate that market prices are insufficient to fund new generation between 2003 and 2009 for both scenarios.

In developing the annual average revenue requirement for a new market entrant, the staff found that the cost of capital for financing these projects and the cost of fuel are the two variables that will weigh heavily in determining the plant's competitiveness and ultimately its profitability. The cost of capital for a new market entrant is especially sensitive to lenders' and investors' perceptions of market uncertainty and risk. Some of that risk is attributable to the immaturity of the competitive market itself and should diminish over time.

Other factors that contribute to market uncertainty and risk include: the frequency and magnitude of price spikes; the development of the demand-side of the market and its effectiveness in moderating price volatility; the presence of price caps in both the energy and ancillary services markets; the development of the rules governing congestion costs; and the mechanisms/process for deciding when upgrades to the transmission system will occur.

Regulatory actions such as changes in environmental laws, both at the regional and national level, and the pace of restructuring in other western states and the rules adopted by these states for treatment of stranded asset costs and mitigating market power, will also shape investors' perceptions of market risk and uncertainty.

Both scenarios show that market clearing prices would not be sufficient to cover the annual average revenue requirement of a new market entrant until 2010. This finding underscores three trends that the staff believes will have a significant impact on future system reliability.

- Future generation resource additions will not occur in a smooth even pattern, but will more likely occur in a cyclical pattern resulting in periods of excess and lean generation capacity.

- A new generator's profitability will depend largely on the prices it is paid for energy during the summer peak demand season, if it is relying solely on the energy market for revenue.

- Market clearing prices during the summer peak demand season may not reach a level necessary to sustain new market entry until reserve margins drop below historic levels usually regarded as necessary for reliable service.

Developers of new power plants will be closely watching how market prices respond to new entry in 2002. Should prices behave in a manner consistent with staff's modeling, subsequent additions of new capacity will most likely be fewer and more spread out than the level assumed in staff's cautious development scenario. Staff will be conducting additional analyses to estimate the impacts of other key variables on market price and supply adequacy trends.

Introduction

In this report, the California Energy Commission staff provides two forecasts of the market clearing price (MCP) for electricity purchased through a second price auction such as that used by the California Power Exchange's (PX) day-ahead energy market. The two MCP forecasts are based on different resource development futures: one reflecting rapid development of many currently announced projects; the other, a more gradual rate of resource development driven by market prices.

The energy market is the principal source of income for most generators in California. Forecasts of future MCPs are therefore an indicator of future profitability for generators. MCPs also provide an important price signal to potential new generators. Developers of new power plants will compare the plant's revenue requirements to the expected revenue from the energy market. Broadly speaking, electricity prices higher than the level needed to cover the plant's revenue requirement indicate new generation capacity is needed; lower prices indicate a surplus of generation capacity exists. In reality, the market structure is more complicated, especially since loads at California's summer peak are so much higher than loads the rest of the year. Both the demand and supply sides of the market will need to adjust to better balance the value of their electricity investments.

Section I of the report begins with a comparison of the two forecasts of annual average MCPs for the years 2000-2010 and discusses the changes in both methodology and inputs underlying this forecast compared to the staff's December 1998 Market Clearing Price forecast.

Section II discusses how the staff developed the scenarios and the decision process involved in determining how much and when new resources would be added both in California and the rest of the Western Systems Coordinating Council (WSCC).

Section III looks at sources of market uncertainty, new market entry, and the emerging trends in future electricity prices that will have significant consequences for future system reliability.

Section I: Market Clearing Price Forecasts

This section provides two forecasts of MCPs[i] for electricity purchased through the PX. The PX oversees a competitive auction that determines the price of electricity on an hourly basis, according to the demand and supply bids submitted by buyers and sellers of electricity. The last generation bid accepted for meeting demand in a particular hour sets the MCP that the PX pays to all generators providing electricity in that hour.[ii] (See Appendix D for a more detailed explanation of the California market design.)

Each of the forecasts presented here represents a different point of view with respect to the timing of new generation additions. One forecast reflects a rapid development scenario in which merchant plant developers who have either received a permit to construct from the Energy Commission, filed an Application for Certification (AFC) with the Commission, or are expected to file an AFC within the next year, proceed immediately to construction as soon as they receive a license. The second forecast reflects the perspective that while new merchant plant developers may have a permit in hand from the Commission, they will adopt a wait-and-see strategy before commencing construction.

Construction of new generation facilities could stretch out because, unlike the regulated market where the recovery of construction costs was guaranteed, the competitive market provides no such guarantees. The staff's second scenario is, therefore, based on the assumption that new power plants will be built when developers perceive that the market price for electricity will be high enough to allow them to recover their costs and make a profit.

The staff's forecast of average monthly MCPs is best characterized as the expected trend. Actual average monthly MCPs will fluctuate above or below the forecasted MCPs because actual weather/demand, fuel prices, and outage conditions will vary from those assumed in staff's forecast.

Table I-1 below compares the annual average MCPs from the two scenarios in nominal dollars and real year 2000 dollars. Both scenarios show MCPs declining in nominal and real dollars from 2001 to 2003 due to new power plants coming on-line. The decline under the rapid development scenario is greater because more power plants are added to the system in 2002 and 2003 than are added under the cautious development scenario. From 2003 to 2010, prices rise as demand grows and fewer power plants are built. In 2009, real prices return to their year 2000 levels. The two scenarios are described in greater detail in **Section II** of the report. **Figures I-1** and **I-2** illustrate the difference between the nominal and real annual average MCPs for the two scenarios.

Table I-1
Comparison of Annual Average MCPs
Under Two Development Scenarios
($/MWh)

Year	Rapid Development		Cautious Development	
	Nominal	2000$	Nominal	2000$
2000	28.5	28.5	28.5	28.5
2001	31.0	30.3	31.0	30.3
2002	25.9	24.7	25.9	24.8
2003	23.4	21.9	25.3	23.7
2004	24.8	22.7	26.9	24.6
2005	26.3	23.6	29.1	26.1
2006	27.7	24.2	30.7	26.9
2007	29.1	24.9	31.0	26.5
2008	29.9	24.9	33.2	27.6
2009	36.0	29.1	36.0	29.1
2010	41.9	32.9	41.9	32.9
Annual Growth Rates				
2000-2003	-6.3%	-8.3%	-3.9%	-6.0%
2003-2010	8.6%	6.0%	7.5%	4.8%

Figure I-1
Comparison of Nominal vs. Real
Annual Average MCPs

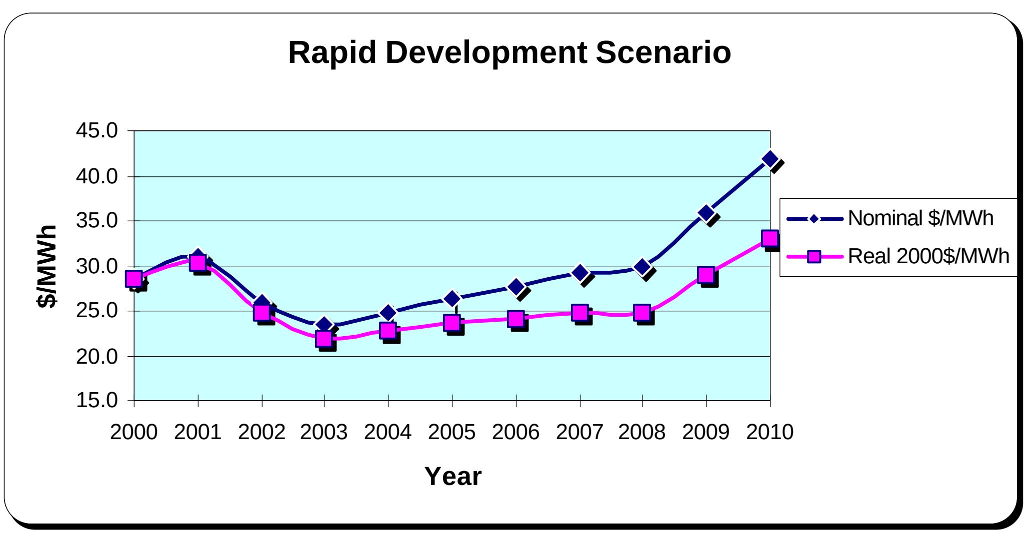
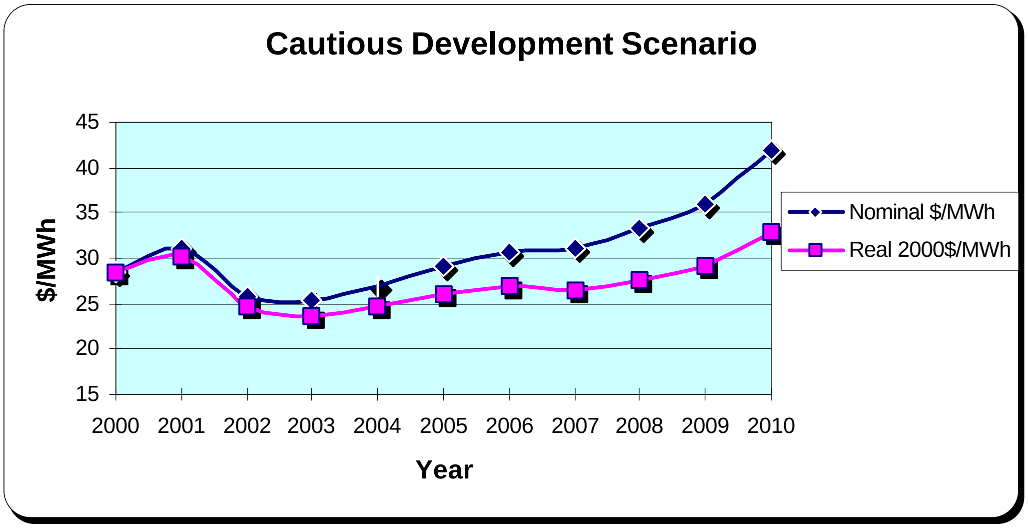


Figure I-2
Comparison of Nominal vs. Real
Annual Average MCPs



Tables I-2 and **I-3** below compare the results of these two alternative resource scenarios to the staff's December 1998 Market Clearing Price forecast.

Table I-2
Rapid Development Scenario
Annual MCPs (Nominal $/MWh)

Year	2000 Forecast	1998 Forecast	% Diff
2000	28.5	26.5	8%
2001	31.0	27.8	3%
2002	25.9	29.6	-13%
2003	23.4	30.6	-23%
2004	24.8	31.9	-22%
2005	26.3	33.1	-20%
2006	27.7	34.5	-20%
2007	29.1	36.0	-19%
2008	29.9	37.5	-20%
2009*	36.0	38.6	-7%
2010*	41.9	39.9	5%

* Staff's 1998 Forecast was for the years 1999-2008.
The 2009 and 2010 values are extrapolated

Table I-3
Cautious Development Scenario
Annual MCPs
(Nominal $/MWh)

Year	2000 Forecast	1998 Forecast	% Diff
2000	28.5	26.5	8%
2001	31.0	27.8	3%
2002	25.9	29.6	-13%
2003	25.3	30.6	-17%
2004	26.9	31.9	-16%
2005	29.1	33.1	-12%
2006	30.7	34.5	-11%
2007	31.0	36.0	-14%
2008	33.2	37.5	-11%
2009*	36.0	38.6	-7%
2010*	41.9	39.9	5%

* Staff's 1998 Forecast was for the years 1999-2008.
The 2009 and 2010 values are extrapolated.

The MCP results for both scenarios are identical in the years 2000 through 2002 and 2009 through 2010. The results are identical because, in the market model[iii] used to produce these estimates of MCPs, the amount of existing and new generation capacity available in these years is identical. The differences between the MCPs from the 1998 forecast and the two scenarios presented in this report are largely attributable to a different methodology, for the years after 2001, and to a different gas price forecast.

Changing Methodology

Both this forecast and the staff's 1998 MCP forecast relied on the results of a regional market model. However, in the previous MCP forecast, the staff only used the MCP results from the model until the annual MCP reached the annual revenue requirement of a new market entrant. Annual MCPs from the model reached this level in the year 2002. Once market prices reached that level, the annual MCP was set equal to the annual revenue requirement of the new entrant. It was the staff's judgement that if the actual MCP fell short of the annual revenue requirement of the new entrant then the viability of the market would be questionable and the Independent System Operator (or the legislature) would have to take remedial action. Market interventions could include capacity payments or other forms of remuneration such as must-run contracts, to attract entry. We were uncertain whether market forces would be allowed to operate if reserve margins dropped below historic levels. Conversely, if the MCP exceeded the revenue requirement of a new market entrant this would attract new entry and drive the MCP lower. **Table I-4** illustrates how the 1998 MCP forecast was constructed. From 1998 to 2001 the 1998 MCP forecast is derived from the market model results. After 2002, the 1998 MCP forecast is equal to the cost of a new entrant.

Table I-4
Construction of 1998 MCP Forecast
(Nominal $/MWh)

Year	Market Model Results	Cost of a New Entrant	MCP Forecast
1998	25.8	28.5	25.8
1999	24.7	27.5	24.7
2000	26.5	27.8	26.5
2001	27.8	28.6	27.8
2002	31.6	29.6	29.6
2003	36.6	30.6	30.6
2004		31.9	31.9
2005		33.1	33.1
2006		34.5	34.5
2007		36.0	36.0
2008		37.5	37.5

Natural Gas Prices

MCPs are very sensitive to the price of natural gas because gas-fired power plants are the plants that set the MCP during most of the peak demand hours. This MCP forecast for the years 2000 and 2001 is 8 percent and 3 percent higher than the MCPs in staff's 1998 forecast largely because of differences between the natural gas prices underlying the two forecasts. **Table I-5** below compares the statewide average gas price from the ***Preliminary 1999 Fuels Report*** (***FR99***) to the previous ***1997 Fuels Report*** (***FR97***) gas price forecast.

Natural gas prices for this current forecast are significantly higher than those used in the 1998 MCP forecast, due primarily to increases in the commodity cost of gas. The methodology underlying the ***FR97*** forecast assumed that the investor-owned utilities (IOUs) retained ownership of their fossil fuel-fired power plants. The IOU's divestiture of these plants affected certain assumptions within the new ***FR99*** forecast. First, the utilities' revenue allocation formula changed to recover more revenue from the electric generation customers. Second, in the ***Preliminary FR99*** forecast, the staff assumed that the gas supply pool from which divested plants purchase their gas will be more expensive than the sources the California IOUs had access to when they owned the plants. Once the utilities sold their fossil-fuel plants, the associated contracts for firm interstate gas pipeline capacity were assumed to be no longer applicable. Additional detail on the ***FR99*** gas prices and the price forecast methodology is available in **Appendix A**.

Table I-5
Comparison of Statewide Average Natural Gas Price Forecasts
Cost of Gas to Electric Generators (EG)*
2000$

Year	Preliminary FR99 EG $/MMBtu	Final FR97 EG $/MMBtu	% Diff
2000	2.54	2.22	14%
2001	2.52	2.26	11%
2002	2.48	2.30	8%
2003	2.53	2.35	8%
2004	2.58	2.39	8%
2005	2.62	2.44	7%
2006	2.65	2.47	7%
2007	2.69	2.51	7%
2008	2.72	2.56	6%
2009	2.76	2.60	6%
2010	2.79	2.62	7%

*Average created by weighting the gas price forecasts for PG&E, SoCal Gas, and SDG&E by 0.6, 0.3, and 0.1 respectively.

Developing Bids

The hourly bids submitted by generators to the PX determine the MCP. Modeling the function of a market such as the California PX, therefore, required that the staff develop these bids. Staff's regional simulation model Multisym™ allows the user two choices: to bid the plant's output at its variable operating cost, or to bid a portion or multiples of the plant's fixed and variable operating costs. For thermal plants, the variable operating cost is simply the product of a plant's incremental heat rate, measured in Btus/kWh, times its fuel cost ($/MMBtu), plus its variable operation and maintenance (O&M) cost. For hydro facilities the variable operating cost is simply its variable O&M.

In constructing the bids, the staff first identified those plants that would be price-takers, i.e., would not set the MCP, and those that had the potential to be price-setters, i.e., plants that could set the MCP. Large coal and nuclear plants, generators with Standard Offer contracts, and hydro facilities are treated as generation that is scheduled rather than bid and therefore are price-takers. They were bid in at their variable operating cost.

Potential price-setters were assumed to be in-state and out-of-state oil/gas-fired steam generators, combined-cycle plants and in-state combustion turbines. For these plants, a single bidding strategy was developed. Historical monthly PX prices were used as a guideline for estimating how much of the generators' fixed costs to include in their bids. Price-setting plants were first bid in at their variable operating cost. The resulting average monthly MCPs from the model were then compared to actual average monthly MCPs from the PX to date.

For most months of the year, the actual average monthly MCPs have been either at a level equal to, or lower than, the MCPs from the model when all plants were bidding in at the variable operating cost. The staff used information on factors that influence market conditions, such as temperature and resource availability, to determine whether the historical prices for a particular month were unusual, or what could be expected under average/ expected market conditions. Based on this information, the staff determined that for the months November through June all price-setting plants would bid their incremental operating cost.

For the period July through October, the staff made several runs where portions of the price-setting plant's variable O&M and fixed costs were added to their bids. These additions to bids were done until the resulting monthly average MCP from the model reached a level which the staff believed to be probable, given the underlying assumptions in the model with respect to resource availability and demand and the historical performance of the market. **Table I-6** provides the historical monthly unconstrained MCP for 1998 and 1999 along with the monthly forecast of MCPs from the Multisym™ model for the years 2000 and 2001. **Figure I-3** illustrates that the forecasted monthly values closely follow the historical trend in PX prices.

To the extent that the forecasted monthly prices deviate significantly from historical monthly prices, such as those that occurred in October 1999, these differences can be attributed to abnormal market conditions influencing the price. (**Appendix B**, which compares last year's forecast to the historical PX market, describes those unique market conditions that caused market prices to deviate from what would have occurred under expected/average market conditions.)

Although the PX market has only two years experience, the expected trend in average monthly MCPs is low in the winter and spring, higher in the fall, and highest in the summer. The MCPs in 1998 followed this seasonal pattern, as does the staff's forecast of monthly MCPs. MCPs in 1999 exhibited a much different pattern. The monthly average MCP for the summer months was lower than the price for the fall and winter months. Factors contributing to these lower summer prices were an unusually mild summer and greater than expected hydro availability during the summer from the Northwest due to a late snow melt. The late snow melt also contributed to spring prices being higher than would be expected, since greater than normal levels of fossil generation were needed to replace the late hydro run-off. The high monthly average MCPs seen in October and November were the result of a combination of factors including warmer than expected temperatures, derates on the transmission lines between California and the Northwest and on the transmission lines connecting northern and southern California, and unexpected plant outages.

Table I-6
Comparison of Historical Monthly MCPs
To Forecasted MCPs
($/MWh)

Month	1998 PX Actual	1999 PX Actual	2000 Forecasted	2001 Forecasted
Jan		21.0	27.7	30.4
Feb		19.0	24.1	27.7
Mar		18.8	23.3	24.1
Apr	22.6	24.0	20.0	20.8
May	11.6	23.6	18.5	19.2
Jun	12.1	23.5	18.8	19.4
Jul	32.4	28.9	28.0	29.8
Aug	39.5	32.3	40.9	48.6
Sep	34.0	33.9	45.3	50.9
Oct	26.6	47.6	32.2	33.9
Nov	25.7	37.0	31.6	33.1
Dec	29.1	29.7	30.7	33.9
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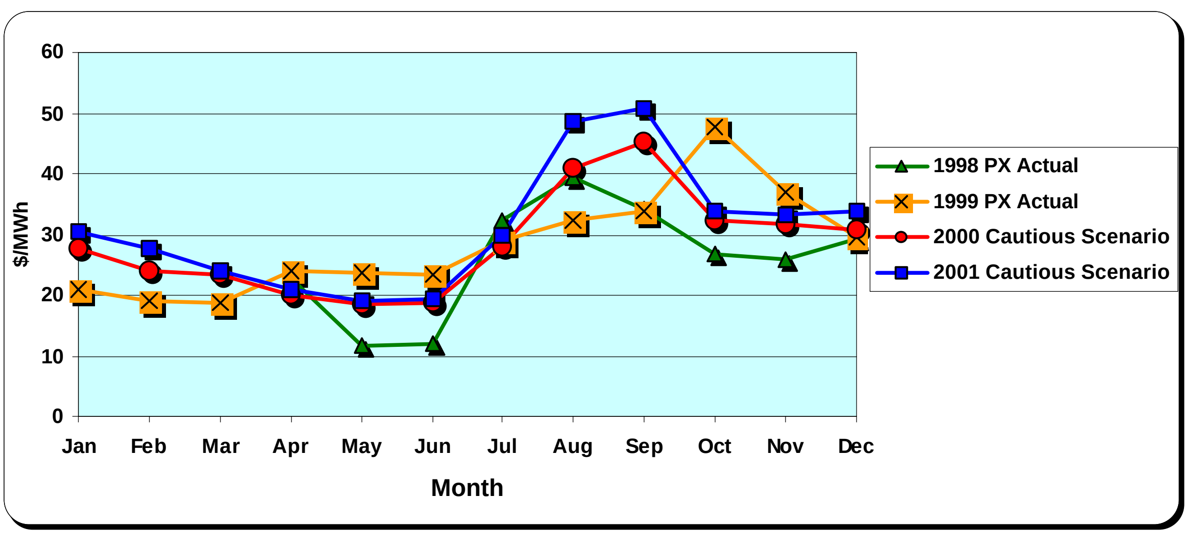
Average	26.0	28.3	28.5	31.0

Figure I-3
Comparison of Historical Monthly MCPs
To Forecasted MCPs
Under the Cautious Development Scenario



Monthly and Sub-Period MCPs

For both scenarios, in 2000 through 2002 and 2009 through 2010, the monthly MCPs are identical because the generation capacity in the model is identical. **Table I-7** and **Table I-8** provide the monthly MCPs from the Multisym™ model for the two scenarios for the years 2002 through 2010. (Monthly values for 2000 and 2001 were provided in **Table I-6**.)

Table I-7
Rapid Development Scenario
Monthly MCPs
(Nominal $/MWh)

Month	2002	2003	2004	2005	2006	2007	2008	2009	2010
Jan	26.6	23.0	24.3	25.8	26.9	27.1	30.1	33.4	38.1
Feb	24.8	22.4	22.6	24.8	25.9	26.2	26.8	32.0	34.5
Mar	22.0	20.8	21.7	23.0	23.8	24.1	25.7	28.2	29.7
Apr	20.1	19.3	20.3	21.4	22.5	22.7	24.0	25.0	26.7
May	18.6	17.4	18.7	20.1	21.1	22.3	23.3	24.7	26.4
Jun	18.8	17.5	18.9	19.9	20.6	22.0	23.2	24.9	26.6
Jul	26.7	26.0	27.6	29.1	30.7	32.5	26.5	37.0	42.7
Aug	32.1	28.2	30.2	32.6	34.7	38.6	45.9	57.5	75.3
Sep	34.7	29.3	31.3	33.3	34.9	38.8	40.3	58.7	75.3
Oct	29.6	27.9	29.6	30.7	31.9	34.2	27.6	39.4	43.6
Nov	27.9	24.3	25.4	27.0	28.7	29.7	31.6	34.8	41.6
Dec	28.4	24.8	26.5	28.0	29.8	30.9	33.5	35.6	41.3
Annual Avg.	**25.9**	**23.4**	**24.8**	**26.3**	**27.7**	**29.1**	**29.9**	**36.0**	**41.9**

Table I-8
Cautious Development Scenario
Monthly MCPs
(Nominal $/MWh)

Month	2002	2003	2004	2005	2006	2007	2008	2009	2010
Jan	26.6	25.0	26.6	28.9	28.1	28.1	31.1	33.4	38.1
Feb	24.8	23.6	23.6	26.8	26.7	28.0	27.4	32.0	34.5
Mar	22.0	21.4	22.9	24.1	24.4	24.8	26.5	28.2	29.7
Apr	20.1	20.5	21.9	22.9	23.2	23.6	24.3	25.0	26.7
May	18.6	19.0	20.0	21.2	22.5	23.0	23.7	24.7	26.4
Jun	18.8	19.2	20.2	21.1	22.5	22.8	23.8	24.9	26.6
Jul	26.7	27.1	28.8	30.5	32.6	33.9	34.9	37.0	42.7
Aug	32.1	31.0	33.7	38.6	45.7	44.3	50.2	57.5	75.3
Sep	34.7	32.2	35.9	40.3	47.1	44.1	51.1	58.7	75.3
Oct	29.6	29.0	31.1	32.0	34.0	35.3	37.0	39.4	43.6
Nov	27.9	27.0	28.9	30.7	30.6	31.1	33.0	34.8	41.6
Dec	28.4	27.9	29.3	31.1	30.8	32.3	34.4	35.6	41.3
Annual Avg.	**25.9**	**25.3**	**26.9**	**29.1**	**30.7**	**31.0**	**33.2**	**36.0**	**41.9**

Tables I-9 and **I-10** present the same monthly information in real (2000) dollars.

Table I-9
Rapid Development Scenario
Monthly MCPs
($/MWh)
Real 2000$

Month	2002	2003	2004	2005	2006	2007	2008	2009	2010
Jan	25.4	21.5	22.3	23.1	23.5	23.2	25.1	27.1	29.9
Feb	23.7	20.9	20.7	22.2	22.7	22.3	22.3	25.9	27.1
Mar	21.0	19.5	19.9	20.6	20.8	20.6	21.4	22.8	23.3
Apr	19.2	18.1	18.6	19.2	19.7	19.4	19.9	20.2	21.0
May	17.8	16.3	17.1	18.0	18.5	19.0	19.4	20.0	20.7
Jun	18.0	16.4	17.3	17.8	18.1	18.7	19.3	20.2	20.9
Jul	25.5	24.3	25.3	26.1	26.9	27.8	22.0	30.0	33.6
Aug	30.7	26.4	27.7	29.2	30.4	33.0	38.2	46.5	59.2
Sep	33.2	27.4	28.7	29.8	30.5	33.1	33.6	47.5	59.2
Oct	28.3	26.1	27.1	27.5	27.9	29.2	23.0	31.9	34.3
Nov	26.7	22.7	23.3	24.2	25.1	25.4	26.3	28.2	32.7
Dec	27.2	23.2	24.3	25.1	26.1	26.3	27.9	28.8	32.5
Annual Ave.	**24.7**	**21.9**	**22.7**	**23.6**	**24.2**	**24.9**	**24.9**	**29.1**	**32.9**

Table I-10
Cautious Development Scenario
Monthly MCPs
($/MWh)
Real 2000$

Month	2002	2003	2004	2005	2006	2007	2008	2009	2010
Jan	25.4	23.4	24.3	25.9	24.6	24.0	25.8	27.1	29.9
Feb	23.7	22.1	21.6	24.0	23.4	23.9	22.8	25.9	27.1
Mar	21.0	20.0	21.0	21.6	21.3	21.2	22.0	22.8	23.3
Apr	19.2	19.2	20.1	20.5	20.3	20.1	20.2	20.2	21.0
May	17.8	17.8	18.4	19.0	19.7	19.6	19.7	20.0	20.7
Jun	18.0	17.9	18.5	18.9	19.7	19.5	19.8	20.2	20.9
Jul	25.5	25.3	26.4	27.3	28.5	28.9	29.0	30.0	33.6
Aug	30.7	29.0	30.8	34.6	40.0	37.8	41.8	46.5	59.2
Sep	33.2	30.1	32.9	36.1	41.3	37.7	42.5	47.5	59.2
Oct	28.3	27.2	28.4	28.7	29.8	30.1	30.8	31.9	34.3
Nov	26.7	25.2	26.5	27.6	26.7	26.5	27.5	28.2	32.7
Dec	27.2	26.1	26.8	27.9	27.0	27.6	28.6	28.8	32.5
Annual Ave.	**24.7**	**23.7**	**24.6**	**26.1**	**26.9**	**26.5**	**27.6**	**29.1**	**32.9**

The staff developed subperiod MCPs for an average weekday and weekend by peak and off-peak periods by creating hourly MCPs for each month using a scaling routine based on a simple regression analysis that correlated historical hourly MCPs and hourly PX load for each month. Each month is represented as an equivalent week (168 hours). The scaling routine was first developed for our 1998 MCP forecast and has been modified slightly for this forecast.[iv] The hourly and subperiod MCPs for both scenarios for all months in the forecast years are available in EXCEL spreadsheets that can be downloaded from the Commission web site.

Table I-11 provides the average annual, on-peak and off-peak subperiod MCPs for an average weekday from the rapid development scenario. Peak hours are defined as Monday through Sunday 7:00 a.m. to 11:00 p.m.. The off-peak period is the remaining hours, Monday through Sunday 11:00 p.m. to 7:00 a.m.. The annual average MCP for the off-peak period is between 42 and 43 percent lower than the peak period MCP. **Figure I-4** illustrates the difference between weekday on-peak and off-peak period MCPs. **Table I-12** and **Figure I-5** provide the same information for an average weekend day. **Tables I-13** and **I-14** and **Figures I-6** and **I-7** provide the subperiod weekday/weekend day data for the cautious development scenario.

The staff notes that all the MCPs presented here are an average for the entire ISO control area. We have not provided separate MCPs for the three ISO congestion management zones (northern, central, and southern California). Zonal price differences do exist and at times can be significant. These price differences should decrease over time. If prices are higher in one zone because of congestion, these high prices will provide a price signal to new generators to locate in that zone, thus eliminating the congestion and lowering the zone's MCP. In specific situations, a price might not rise sufficiently to justify a plant, because power plants are "lumpy investments" and are not available in an infinite number of sizes matched exactly to local needs. And, even if prices do justify a plant, local conditions may be so constrained by other parameters that a plant is not built.

Table I-11
Subperiod MCPs
Average Weekday
Rapid Development Scenario
($/MWh)

Year	Annual Avg.	On-Peak	Off-Peak
2000	30.4	35.4	20.5
2001	33.2	38.6	22.3
2002	27.6	32.1	18.6
2003	25.0	29.1	16.8
2004	26.5	30.8	17.8
2005	28.1	32.8	18.9
2006	29.6	34.4	19.8
2007	31.1	36.3	20.8
2008	32.0	37.3	21.4
2009	38.5	44.9	25.7
2010	44.9	52.4	29.8

Figure I-4
On-Peak vs. Off-Peak Period MCPs
Average Weekday
Rapid Development Scenario
($/MWh)

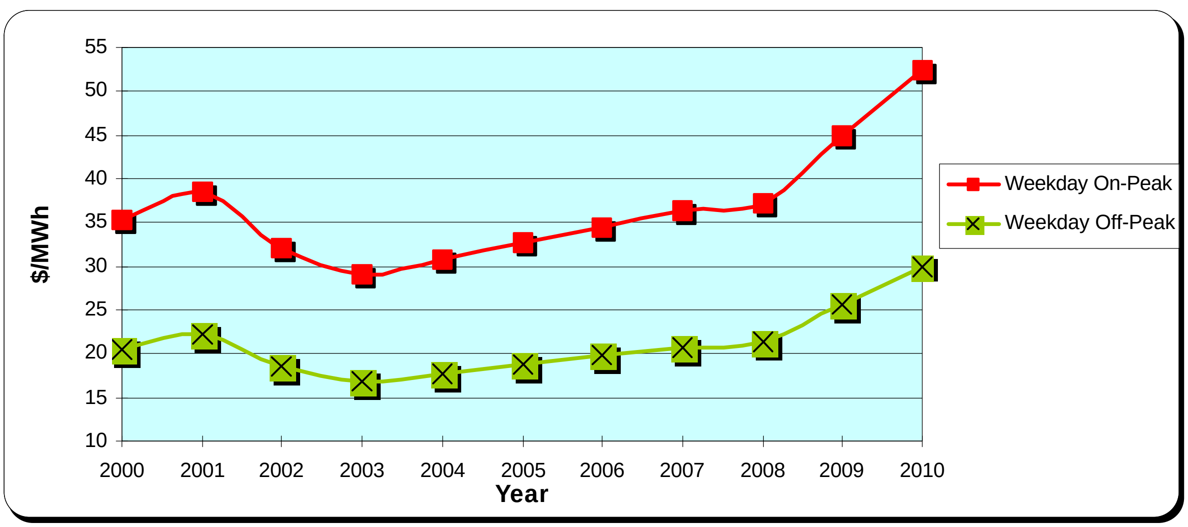


Table I-12
Subperiod MCPs
Average Weekend Day
Rapid Development Scenario
($/MWh)

Year	Annual Avg.	On-Peak	Off-Peak
2000	23.5	26.3	18.0
2001	25.6	28.6	19.6
2002	21.5	24.0	16.4
2003	19.4	21.8	14.8
2004	20.5	23.0	15.6
2005	21.8	24.4	16.5
2006	22.9	25.7	17.4
2007	24.1	27.0	18.3
2008	24.7	27.7	18.8
2009	29.6	33.1	22.6
2010	34.3	38.4	26.3

Figure I-5
On-Peak vs. Off Peak Period MCPs
Average Weekend Day
Rapid Development Scenario
($/MWh)

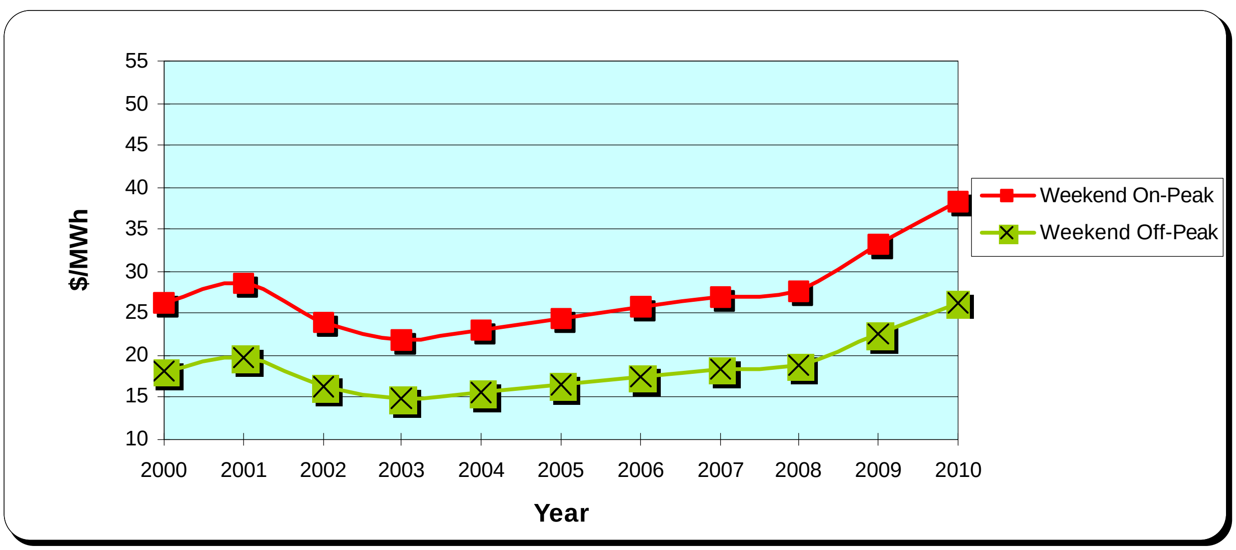


Table I-13
Subperiod MCPs
Average Weekday
Cautious Development Scenario
($/MWh)

Year	Annual Avg.	On-Peak	Off-Peak
2000	30.4	35.4	20.5
2001	33.2	38.6	22.3
2002	27.6	32.1	18.6
2003	27.0	31.4	18.1
2004	28.8	33.5	19.3
2005	31.1	36.2	20.8
2006	32.9	38.4	21.9
2007	33.1	38.6	22.1
2008	35.5	41.4	23.7
2009	38.5	44.9	25.7
2010	44.9	52.4	29.8

Figure I-6
On- Peak vs. Off Peak Period MCPs
Average Weekday
Cautious Development Scenario
($/MWh)

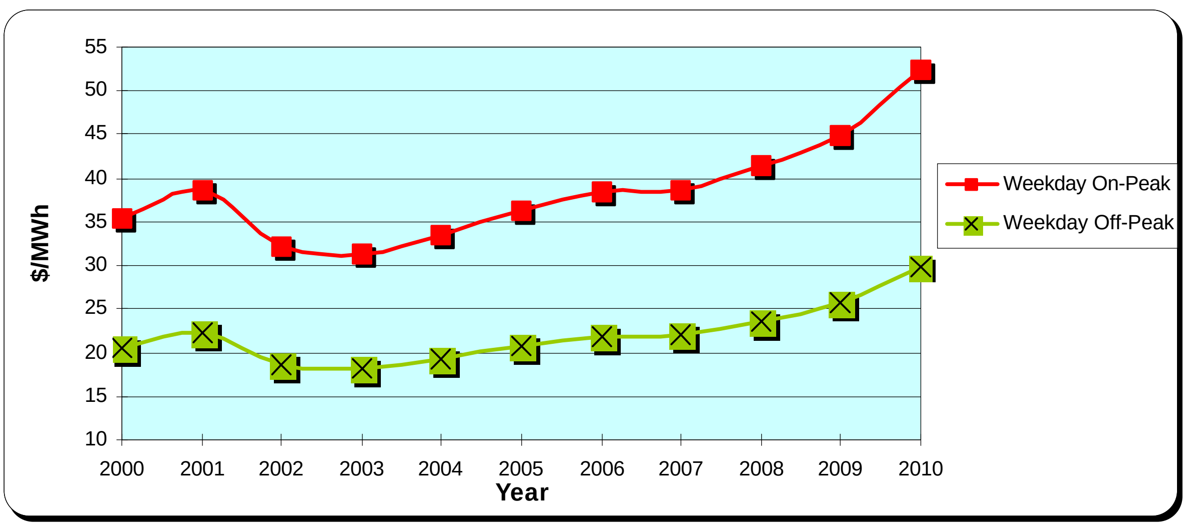
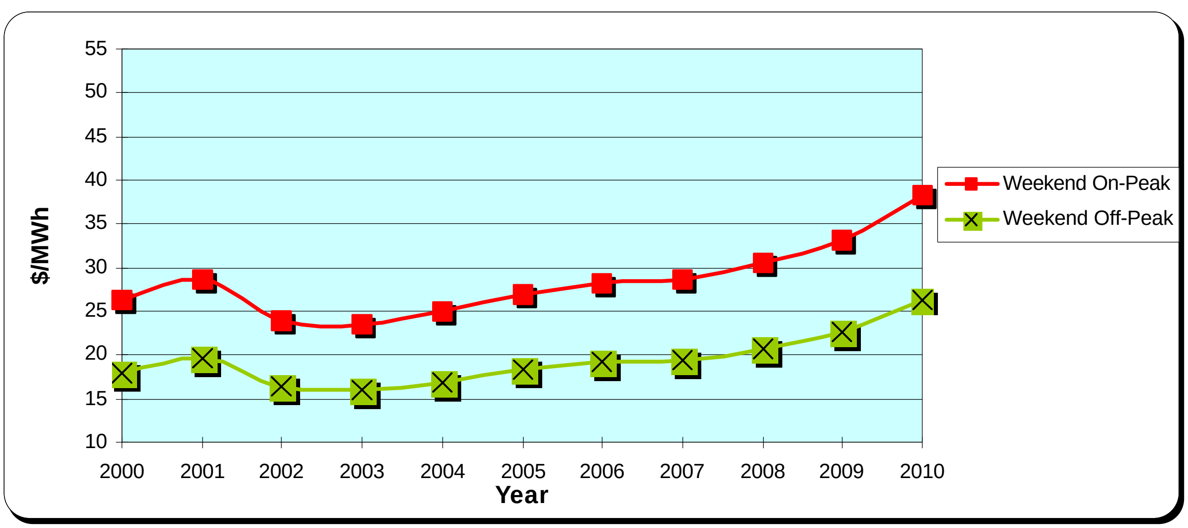


Table I-14
Subperiod MCPs
Average Weekend Day
Cautious Development Scenario
($/MWh)

Year	Annual Avg.	On-Peak	Off-Peak
2000	23.5	26.3	18.0
2001	25.6	28.6	19.6
2002	21.5	24.0	16.4
2003	20.9	23.5	15.9
2004	22.3	25.0	17.0
2005	24.0	26.9	18.3
2006	25.3	28.3	19.2
2007	25.5	28.6	19.4
2008	27.3	30.6	20.8
2009	29.6	33.1	22.6
2010	34.3	38.4	26.3

Figure I-7
On-Peak vs. Off-Peak Period MCPs
Average Weekend Day
Cautious Development Scenario
($/MWh)



[i] All MCPs referred to in this report are for the PX's hourly day ahead unconstrained market and unweighted by load.

[ii] Until March 2002, California's investor-owned utilities (PG&E, SCE, and SDG&E) must buy from *and* sell *all* of their generation through the California Power Exchange (PX), which will auction electric power demand and supply. Other market participants — such as independent power producers (IPPs), municipal generators, and utilities located outside of California, aggregators, etc. — have the option of buying from, or selling electricity through the PX or selling directly to a customer without going through the PX.

[iii] The MCPs from the staff's two scenarios were outputs of the Multisym™ model, a licensed product of Henwood Energy Services Inc. Multisym™ emulates the hourly bidding market of the California PX, as well as the commitment and dispatch of generators and the transmission of electricity throughout the WSCC reliability region.

[iv] See Appendix D, "Hourly MCP Scaling Methodology," in *1998 Market Clearing Price Forecast for the California Market: Forecast Methodology & Analytical Issues*, California Energy Commission, December 1998, Publication No. 300-98-015.

Section II: Alternative Development Scenarios

This section describes how the staff constructed their two scenarios of future power plants additions for California and the rest of the WSCC. When the staff prepared the 1998 MCP forecast, six Applications for Certification (AFCs) for new power plants had been filed with the Energy Commission. By the end of 1999, three of the six AFCs had been approved, and developers had proposed to build another 34 large gas-fired power plants in the State. These 34 projects include those where the developer has either filed an AFC, has made a public announcement regarding their intent to file an AFC, or has contacted the Commission staff privately but has not made any public announcement about filing an AFC.

Because of the large number of new power plants proposed in the State, the staff believes that using the assumption that the annual revenue requirement of a new market entrant would determine the long-run MCP would be inaccurate. The staff believed that a new approach, based on specific assumptions about the timing and quantity of new resource additions, would more accurately describe future MCPs in the competitive market. The capacity of proposed new plants significantly exceeds peak demands from load growth and would materially impact prices.

In-State Additions

It is highly speculative as to which power plants will be built and when. The staff viewed it as unlikely that all of the plants that developers have indicated an interest in building will be built within the MCP forecast period. This assumption, of course, is sensitive to whether certain existing resources, such as the nuclear plants and older fossil fuel-fired plants that are receiving reliability must-run payments, will continue to operate in the future. In deciding which proposed plants to include in the forecast, the staff first included those that had already received approval from the Commission or would likely receive approval within the next 6 months and still have an on-line date prior to the Summer of 2002.

After 2002, the staff relied on a combination of factors which would limit the number of plants and spread out the development of new projects amongst the major developers. Location was one of the factors considered because of doubts as to whether the existing transmission network could accommodate all these proposed plants without undergoing significant upgrades and increases in capacity.

Transmission congestion should provide an economic incentive as to where new generation should locate. For example, congestion on Path 15, which represented the border between the northern and southern California congestion pricing zones,[i] is congested primarily in the south to north direction. To relieve this congestion, generators in northern California receive a higher MCP, which should provide a stronger economic incentive for locating new generation in northern California. Therefore, the staff's additions of new resources tend to include more new generation in northern California over southern California.

Congestion within a zone (intrazonal congestion), as well as the adequacy of natural gas pipeline capacity, are two factors that the staff considered as potentially limiting the number of plants built within a zone. The staff's assessment of the potential for intrazonal congestion was based on an examination of the findings contained in the system impact studies submitted to the Commission as part of the certification process for new power plants.[ii] Two plants proposed for northern California were found to have their output limited to avoid transmission line overloads. Intrazonal congestion was not a problem in southern California because the transmission networks in southern California are highly interconnected and contain fewer radial transmission lines than northern California.

Natural gas pipeline capacity was found to be adequate in most of the state. Gas suppliers have also indicated that they are more than willing to increase gas pipeline capacity to an area if there is a demand. Increasing gas pipeline capacity is also a relatively easier task than building new transmission lines.

Proposed projects were also screened based on the Commission staff's estimate of which projects may have a more difficult time in mitigating potential environmental impacts, as well as the presence of local opposition. Projects that fell into this category were seen as having a lower probability of being built within the forecast period. Because of environmental concerns, projects that involved repowers or used existing power plant sites were viewed as having a higher probability of being built before "green" site projects.

Considering all of the factors described above, the staff judged that 19 of the proposed power plants had a higher probability of being built within the next ten years than the remaining 21. This number of plants represents a total of 9,186 MW of new net capacity being added. All of these plants are merchant plants assumed to be selling all of their output into the California PX. Another 157 MW of capacity from renewable energy projects was also added in the ISO control area over the next 10 years for a total of 9,343 MW.

The first development scenario, the rapid development scenario, relies on the information from developers regarding when they intend to build and operate their new power plants once the Commission approves their AFC. The details of this scenario are shown in **Table II-1**. The table shows new additions, retirements of existing capacity and replacement of that capacity with new or repowered capacity. Under the rapid development scenario, 2,840 MW are added in 2002 and another 6,398 MW in 2003. The remaining additions involve one replacement/repowering in San Diego in 2006 for a net 252 MW increase and another in central California in 2008 for a net 142 MW decrease. This results in 9,342 MW total.

Table II-2 provides the details of the cautious development scenario. This scenario assumes that proponents of multiple projects will take a more cautious approach, waiting to see how profitable their initial plants will be and if their competitor's plans materialize. Over the 2000 – 2010 forecast period, the same amount of capacity is added in this scenario as in the rapid development scenario. The difference between the two begins in 2003 when eight projects that were on-line in the rapid development scenario in 2003 are deferred in this scenario. The projects that are included in 2002 and 2003 are those that already have been approved by the Commission or are close to the end of the one-year licensing period and involve developments at existing sites. They were assumed to be approved. The eight plants that are deferred in this cautious development scenario come on-line later in the forecast period to prevent the planning reserve margin for the California ISO from falling below 7 percent.[iii]

Figure II-1 illustrates the differences between the two scenarios. In the rapid development scenario, ISO control area planning reserves reach a peak of 22 percent in 2003 and then steadily decline to 7 percent by 2010. In the cautious development scenario, planning reserves reach 13 percent in 2003. New resources are added in the years 2007, 2008, and 2009 to keep reserve margins above 7 percent. By 2010 reserves are at the 7 percent level.

Historically, a 15-20 percent planning reserve margin was regarded as the standard for maintaining adequate reliability. The planning margin was intended to ensure that sufficient generation capacity existed at the time of the peak demand to cover contingencies such as generation capacity and energy lost due to forced outages, dry hydro conditions, or demand forecast error, and still meet minimum operating reserve requirements.[iv] The WSCC[v] requires that control areas (areas that control generation and individually balance electrical load such as the California ISO) within its boundaries maintain a minimum operating reserve of 7 percent.

By using a 7 percent margin as an indicator of when to add new resources in the cautious development scenario, the staff assumed that MCPs would reflect the value of additional generation at the margin, and would be high enough to support investment. This would preserve minimum operating reserve levels.

Table II-3 provides the load-resource balance for the entire State under the cautious development scenario. Outside of the California ISO control area, very few power plants are added in the State over the next ten years. In the LADWP service area, only 10 MW of new renewable energy projects are added. LADWP has ample supplies to meet its obligation to serve and has embarked on an ambitious cost reduction program. In the Imperial Irrigation District, 59 MW of renewable energy projects are added in 2002 and 148 MW of new combustion turbine capacity in 2003. Reserves for the entire State under the cautious development scenario peak at 16 percent in 2003 and reach 9 percent by 2010.

Table II-1
Rapid Development Scenario
California ISO Control Area
(MW)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	MW Net Additions
Total Load	48,380	49,122	50,020	50,861	51,687	51,551	52,212	53,154	54,145	55,127	56,104	
Existing Resources-No Additions	56,326	56,247	56,080	55,958	55,982	54,719	54,689	54,567	54,477	53,963	53,819	
Interruptible Load	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	
Addition/Retirements By Region For Rapid Development Scenario												
Northern California												
Additions	0	0	877	3,722	0	0	0	0	0	0	0	**4,599**
Retirements	0	0	0	-430	0	0	0	0	0	0	0	**(430)**
Central California												
Additions	0	0	1,239	1,360	0	0	0	0	528	0	0	**3,127**
Retirements	0	0	0	-326	0	0	0	0	-676	0	0	**(1,002)**
Southern California												
Additions	0	0	722	2,290	0	0	0	0	0	0	0	**3,012**
Retirements	0	0	0	-634	0	0	0	0	0	0	0	**(634)**
San Diego												
Additions	0	0	2	416	0	0	962	0	0	0	0	**1,380**
Retirements	0	0	0	0	0	0	-710	0	0	0	0	**(710)**
Net CAL-ISO Capacity Additions	0	0	2,840	6,398	0	0	252	0	(148)	0	0	**9,342**
Existing Resources Plus Net Additions	56,326	56,247	58,920	65,196	65,220	63,957	64,179	64,057	63,819	63,305	63,161	
*** Margins Over Load With Net Additions**	**10%**	**8%**	**12%**	**22%**	**20%**	**18%**	**17%**	**15%**	**12%**	**9%**	**7%**	

* Interruptible load is treated as a supply-side resource in existing resources. Reserve margin calculation subtracts interruptible load from resources available. Total load value is firm plus nonfirm (i.e. interruptible) load.

Table II-2
Cautious Development Scenario
California ISO
(MW)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	MW Net Additions
Total Load	48,380	49,122	50,020	50,861	51,687	51,551	52,212	53,154	54,145	55,127	56,104	
Existing Resources-No Additions	56,326	56,247	56,080	55,958	55,982	54,719	54,689	54,567	54,477	53,963	53,819	
Interruptible Load	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	
Addition/Retirements By Region For Price Sensitive Scenario												
Northern California												
Additions	0	0	877	2,056	0	0	0	1,667	0	0	0	**4,600**
Retirements	0	0	0	(430)	0	0	0	0	0	0	0	**(430)**
3												
Additions	0	0	1,239	528	0	0	0	0	945	416	0	**3,128**
Retirements	0	0	0	(326)	0	0	0	0	(676)	0	0	**(1,002)**
Southern California												
Additions	0	0	722	625	0	0	0	0	1,040	625	0	**3,012**
Retirements	0	0	0	(634)	0	0	0	0	0	0	0	**(634)**
San Diego												
Additions	0	0	2	0	0	0	0	1,377	0	0	0	**1,379**
Retirements	0	0	0	0	0	0	0	(710)	0	0	0	**(710)**
Net CAL-ISO Capacity Additions	0	0	2,840	1,819	0	0	0	2,333	1,309	1,041	0	**9,342**
Existing Resource Plus Net Additions	56,326	56,247	58,920	60,617	60,641	59,378	59,348	61,559	62,778	63,305	63,161	
*** Margins Over Load With Net Additions**	**10%**	**8%**	**12%**	**13%**	**12%**	**9%**	**8%**	**10%**	**10%**	**9%**	**7%**	

* Interruptible load is treated as a supply-side resource in existing resources. Reserve margin calculation subtracts interruptible load from resources available. Total load value is firm plus nonfirm (i.e. interruptible) load.

Figure II-1
Comparison of Alternative Resource Additions Scenarios
California ISO Control Area

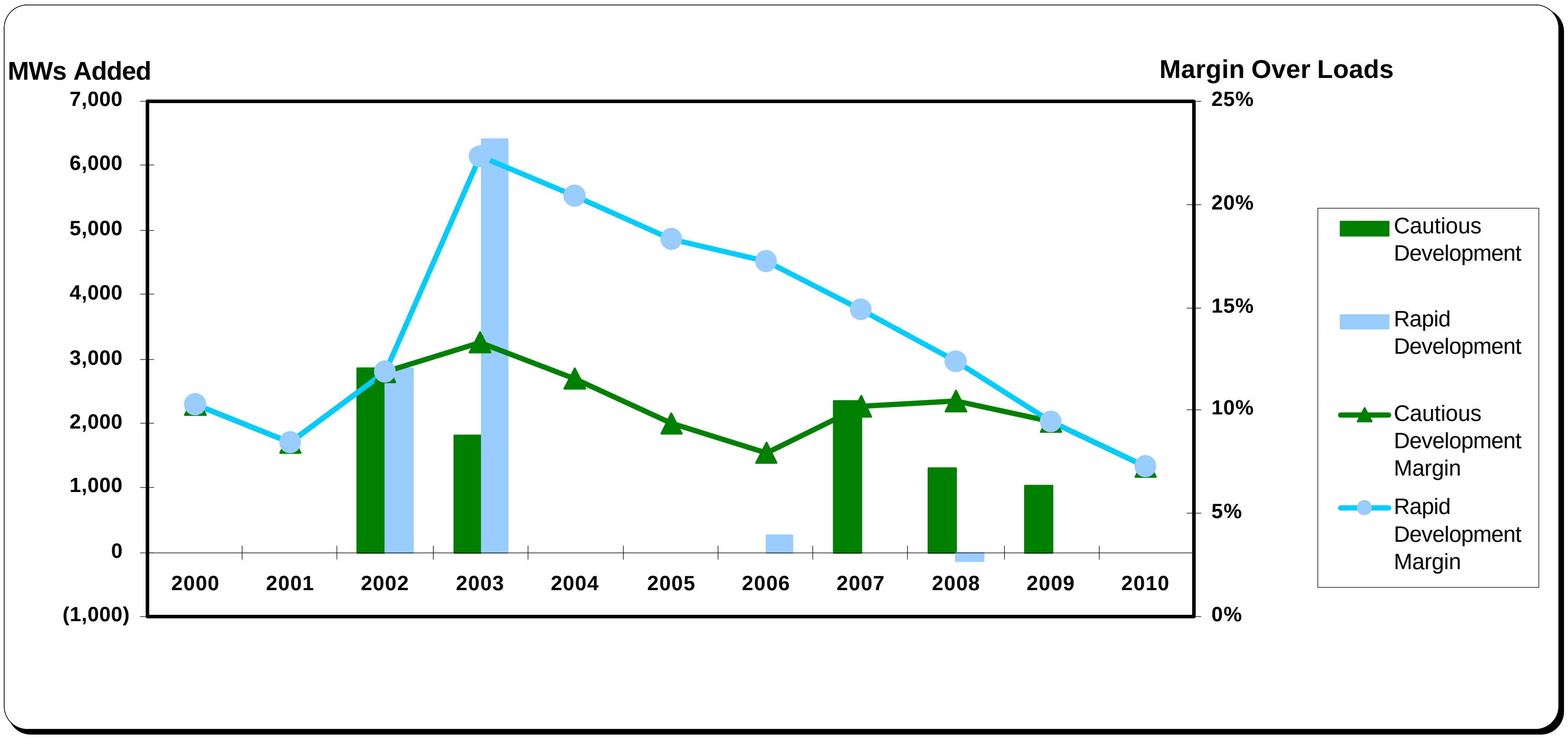


Table II-3
Load Resource Balance for California
Cautious Development Scenario
(MW)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	MW Net Additions
California ISO												
Total Load	48,380	49,122	50,020	50,861	51,687	51,551	52,212	53,154	54,145	55,127	56,104	
Existing Resources-No Additions	56,326	56,247	56,080	55,958	55,982	54,719	54,689	54,567	54,477	53,963	53,819	
Interruptible Load	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	(2,980)	
Net CAL-ISO Capacity Additions	0	0	2,840	1,819	0	0	0	2,333	1,309	1,041	0	**9,342**
Margins Over Load With Net Additions	**10%**	**8%**	**12%**	**13%**	**12%**	**9%**	**8%**	**10%**	**10%**	**9%**	**7%**	
LADWP												
Total Load	6,553	6,584	6,644	6,709	6,742	6,726	6,762	6,825	6,892	6,960	7,033	
Existing Resources-No Additions	9,451	9,451	9,451	9,451	9,451	9,451	9,451	9,451	9,379	9,379	9,379	
Interruptible Load	(270)	(270)	(270)	(270)	(270)	(270)	(270)	(270)	(270)	(270)	(270)	
Net Additions	0	0	10	0	0	0	0	0	0	0	0	**10**
Margin Over Loads With Net Additions	**40%**	**39%**	**38%**	**37%**	**36%**	**37%**	**36%**	**35%**	**32%**	**31%**	**30%**	
Imperial Irrigation District												
Total Load	750	770	791	812	833	854	875	895	915	936	956	
Existing Resources-No Additions	874	874	666	666	666	666	666	666	666	633	633	
Interruptible Load	0	0	0	0	0	0	0	0	0	0	0	
Net Additions	0	0	59	148	0	0	0	0	0	0	0	**207**
Margin Over Loads With Net Additions	**17%**	**14%**	**-8%**	**8%**	**5%**	**2%**	**0%**	**-2%**	**-5%**	**-10%**	**-12%**	
California Total												
Total Load	55,683	56,476	57,455	58,382	59,262	59,131	59,849	60,874	61,952	63,023	64,093	
Existing Resources-No Additions	66,651	66,572	66,197	66,075	66,099	64,836	64,806	64,684	64,522	63,975	63,831	
Interruptible Load	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	
Net Additions	0	0	2,909	1,967	0	0	0	2,333	1,309	1,041	0	**9,559**
Existing Resource Plus Net Additions	66,651	66,572	69,106	70,951	70,975	69,712	69,682	71,893	73,040	73,534	73,390	
*** Margin Over Loads With Net Additions**	**14%**	**12%**	**15%**	**16%**	**14%**	**12%**	**11%**	**13%**	**13%**	**12%**	**9%**	

* Interruptible load is treated as a supply-side resource in existing resources. Reserve margin calculation subtracts interruptible load from resources available. Total load value is firm plus nonfirm (i.e. interruptible) load.

Out-of State Resource Additions

The Multisym™ model, which the staff used to forecast market clearing prices, simulates the generation and transmission of electricity throughout the WSCC. **Figure II-2** depicts the representation of the WSCC in Multisym™. Transfers of electricity on the bulk transmission network within the WSCC contribute to maintaining system reliability throughout the region. One factor that makes these transfers possible is the load diversity between the Northwest, which has its peak demand in the winter, and California and the Southwest, which peak in the summer. Because of the interdependence of these areas for meeting peak season demand, the staff made certain assumptions with respect to generation additions in areas outside of California to ensure that the loads and resources for the WSCC region were in balance.

The staff first gathered information from various sources on planned and proposed generation and retirements in areas outside California.[vi] (A complete listing of these out-of-state projects is provided in **Appendix C**.) Based on this information, the projects were assigned to one of the five categories.

1. Under construction or completed
2. Regulatory approval received
3. Application under review
4. Starting application process
5. Press release only

The staff was able to identify 26,309 MW of new generation planned for the WSCC outside of California. Combined cycle plants fueled by natural gas comprise the majority of the planned generation. **Table II-4** below provides the breakout of this planned generation according to the five categories and the estimated year on-line.

Initially, only projects in the first two categories were added in the model. However, after running the model with just these additions, the model reported unserved energy occurring in certain subregions of the WSCC. To address this problem, generic combined cycle plants were added in these subregions. However, no generic resources were added before 2002.

Figure II-2
Representation of WSCC in Multisym™

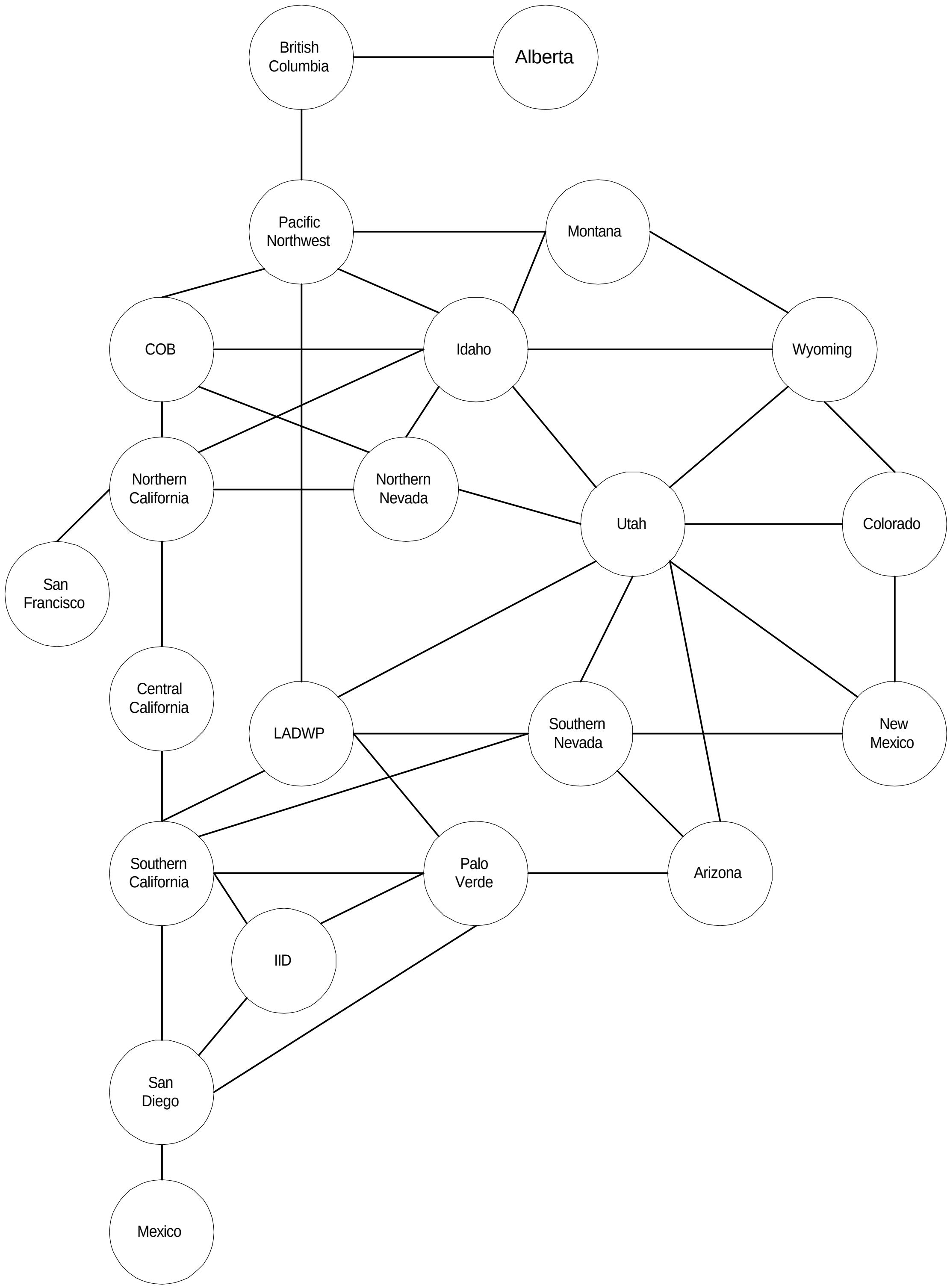


Table II-4
Planned Generation in the WSCC Outside of California
(MW)

Category	Estimated Year of Operation					Total
	1999	2000	2001	2002	2003	
1	806	1,186	2,822	-	250	5,064
2	-	565	1,544	-	-	2,109
3	-	-	-	400	4,294	4,694
4	-	-	30	172	825	1,027
5	-	-	665	3,100	9,650	13,415
Total	**806**	**1,751**	**5,061**	**3,672**	**15,019**	**26,309**

Source: Energy Commission Staff

The criteria staff used for adding generic capacity in a region were based on professional judgement. As a general guideline, the staff added generic resources to a subregion if its planning reserves fell below 6 percent. However, reserves in some areas were allowed to drop below this level. Allowing reserves to drop below 6 percent was done because some areas are currently able to meet peak demand with relatively low reserve margins by relying on purchases of electricity from other regions. The staff also believes that planning reserve margins under competition will be significantly lower than those that prevailed under regulation.

Several factors will contribute to reserves being lower. The primary factors are that there is no guaranteed return for merchant plants and that energy demand with sharp needle peaks may cause a lot of capacity to be idle much of the year. Merchant plant developers will want to have access to the widest possible market to improve their profitability. This factor will translate into an increased reliance on load diversity among regions in the West and an increase in regional transfers of electricity. Plant availability during the peak demand hours should also be greater because these are the hours which will determine whether a generator makes a profit for the year. Demand-side responsiveness should also increase during the high priced peak hours.

Tables II-5 through II-8 provide the load resource balances for each of the four WSCC planning areas and the reserve margins over load after resource additions.

Table II-5
California-Mexico Load Resource Balance
Cautious Development Scenario
(MW)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	MW Net Additions
California												
Total Load	55,683	56,476	57,455	58,382	59,262	59,131	59,849	60,874	61,952	63,023	64,093	
Existing Resources-No Additions	66,651	66,572	66,197	66,075	66,099	64,836	64,806	64,684	64,522	63,975	63,831	
Interruptible Load	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	
Net Additions	0	0	2,909	1,967	0	0	0	2,333	1,309	1,041	0	**9559**
Margin Over Loads With Net Additions	**14%**	**12%**	**15%**	**16%**	**14%**	**12%**	**11%**	**13%**	**13%**	**12%**	**9%**	
CFE-Mexico												
Total Load	1,595	1,690	1,791	1,900	2,015	2,137	2,268	2,407	2,555	2,712	2,879	
Existing Resources-No Additions	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	1,390	
Interruptible Load	0	0	0	0	0	0	0	0	0	0	0	
Planned & Proposed Additions	150	100	450	0	0	225	0	0	0	0	0	**925**
Retirements	0	0	0	0	0	0	0	0	0	0	0	**0**
Additions For Reliability	0	0	0	0	0	0	417	0	0	417	0	**833**
Net Capacity Addition	150	100	450	0	0	225	417	0	0	417	0	**1,758**
Margin Over Loads With Net Additions	**-3%**	**-3%**	**17%**	**10%**	**4%**	**8%**	**20%**	**13%**	**7%**	**16%**	**9%**	
California CFE-Mexico												
Total Load	57,278	58,166	59,246	60,282	61,277	61,268	62,117	63,281	64,507	65,735	66,972	
Existing Resources-No Additions	68,041	67,962	67,587	67,465	67,489	66,226	66,196	66,074	65,912	65,365	65,221	
Interruptible Load	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	
Net Additions	150	100	3,359	1,967	0	225	417	2,333	1,309	1,458	0	**11,317**
Existing Resources Plus Net Additions	68,191	68,212	71,196	73,041	73,065	72,027	72,414	74,625	75,772	76,682	76,538	
*** Margin Over Loads With Net Additions**	**13%**	**12%**	**15%**	**16%**	**14%**	**12%**	**11%**	**13%**	**12%**	**12%**	**9%**	

* Interruptible load is treated as a supply-side resource in existing resources. Reserve margin calculation subtracts interruptible load from resources available. Total load value is firm plus nonfirm (i.e., interruptible) load.

Table II-6
Load Resource Balance for Arizona-New Mexico-Southern Nevada
(MW)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	MW Net Additions
Arizona-New Mexico-So Nevada												
Total Load	22,189	22,585	22,821	23,368	23,937	24,507	25,072	25,565	26,178	26,765	27,407	
Existing Resources-No Additions	22,369	21,721	22,127	22,227	21,787	21,533	21,430	21,435	21,422	21,390	21,390	
Interruptible Load	(791)	(802)	(812)	(822)	(833)	(844)	(849)	(854)	(854)	(854)	(854)	
Addition/Retirements By Region												
Arizona												
Additions	0	828	0	417	2,120	1,000	0	0	0	0	0	**4,365**
Retirements	0	0	0	0	0	0	0	0	0	0	0	**0**
Additions For Reliability	0	0	0	0	0	0	0	0	0	0	0	**0**
New Mexico												
Additions	140	0	0	0	0	0	0	0	0	0	0	**140**
Retirements	0	0	0	0	0	0	0	0	0	0	0	**0**
Additions For Reliability	0	0	0	0	0	0	417	0	0	0	0	**417**
So Nevada												
Additions	480	520	0	0	0	0	0	0	0	0	0	**1,000**
Retirements	0	0	0	0	0	0	0	0	0	0	0	**0**
Additions For Reliability	0	0	625	417	0	0	0	0	0	0	0	**1,042**
Net Additions	620	1,348	625	834	2,120	1,000	417	0	0	0	0	**6,963**
Existing Resources Plus Net Additions	22,989	23,689	24,720	25,654	27,334	28,080	28,393	28,398	28,385	28,353	28,353	
*** Margin Over Loads With Net Additions**	**0%**	**1%**	**5%**	**6%**	**11%**	**11%**	**10%**	**8%**	**5%**	**3%**	**0%**	

* Interruptible load is treated as a supply-side resource in existing resources. Reserve margin calculation subtracts interruptible load from resources available. Total load value is firm plus nonfirm (i.e., interruptible) load.

Table II-7
Load Resource Balance for Rocky Mountain Region
(MW)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	MW Net Additions
Rocky Mtn. Power Region												
Total Load	10,206	10,353	10,540	10,758	11,011	11,193	11,486	11,766	12,050	12,359	12,661	
Total Existing Resources	11,962	11,856	11,806	11,996	11,997	11,997	11,997	11,997	11,997	11,997	11,997	
Interruptible Load	(291)	(291)	(291)	(291)	(292)	(292)	(292)	(292)	(292)	(292)	(292)	
Addition/Retirements By Region												
Colorado												
Additions	565	214	0	240	0	0	0	0	0	0	0	**1,019**
Retirements	0	0	0	(90)	0	0	0	0	0	0	0	**(90)**
Additions For Reliability	0	0	0	0	0	0	0	0	0	480	0	**480**
Wyoming												
Additions	20	20	0	0	0	0	0	0	0	0	0	**40**
Retirements	0	0	0	0	0	0	0	0	0	0	0	**0**
Additions For Reliability	0	0	0	0	0	0	0	0	0	0	0	**0**
Net Additions	585	234	0	150	0	0	0	0	0	480	0	**1,449**
Existing Resource Plus Net Additions	12,547	12,675	12,625	12,965	12,966	12,966	12,966	12,966	12,966	13,446	13,446	
*** Margin Over Loads With Net Additions**	**20%**	**20%**	**17%**	**18%**	**15%**	**13%**	**10%**	**8%**	**5%**	**6%**	**4%**	

* Interruptible load is treated as a supply-side resource in existing resources. Reserve margin calculation subtracts interruptible load from resources available. Total load value is firm plus nonfirm (i.e., interruptible) load.

Table II-8
Load Resource Balance for Pacific Northwest
(MW)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	MW Net Additions
Alberta-BC Hydro- Northwest												
Total Load	63,596	64,264	65,047	65,906	67,286	68,261	69,361	70,084	70,986	71,968	72,328	
Total Existing Resources	76,451	75,682	76,239	77,076	77,162	77,717	77,835	77,835	77,835	77,835	77,819	
Interruptible Load	(817)	(817)	(817)	(817)	(817)	(817)	(817)	(817)	(817)	(817)	(817)	
Addition/Retirements By Region												
Alberta												
Additions	883	38	675	0	0	0	0	0	0	0	0	**1,596**
Retirements	0	0	(72)	(574)	0	0	0	0	0	0	0	**(646)**
Additions For Reliability	0	0	0	0	480	0	0	480	0	0	480	**1,440**
BC Hydro												
Additions	43	38	250	0	0	0	0	0	0	0	0	**331**
Retirements	0	0	0	0	0	0	0	0	0	0	0	**0**
Additions For Reliability	0	0	0	0	0	0	0	0	0	0	0	**0**
Northwest												
Additions	7	1,220	0	720	0	0	0	0	0	0	0	**1,947**
Retirements	(11)	0	0	0	0	0	0	0	0	0	0	**(11)**
Additions For Reliability	0	0	0	0	0	0	0	0	0	0	0	**0**
Net Capacity Addition Alberta-BCHydro- NW	922	1,296	853	146	480	0	0	480	0	0	480	**4,657**
Existing Resource Plus Net Additions	77,373	77,900	79,310	80,293	80,859	81,414	81,532	82,012	82,012	82,012	82,476	
*** Margin Over Loads With Net Additions**	**20%**	**20%**	**21%**	**21%**	**19%**	**18%**	**16%**	**16%**	**14%**	**13%**	**13%**	

* Interruptible load is treated as a supply-side resource in existing resources. Reserve margin calculation subtracts interruptible load from resources available. Total load value is firm plus nonfirm (i.e., interruptible) load.

[i] On August 26, 1999, the ISO Board of Governors approved the creation of a new congestion zone between Path 15 and Path 26. This third zone is defined as the central California zone in staff's modeling.

[ii] These included System Impact Studies for the La Paloma Power Project, the Sunrise Cogeneration and Power Project, the Elk Hills Power Project, the Pittsburg District Energy Facility, Delta Energy Center Project, the Morro Bay Power Plant Modernization and the Moss Landing Power Plant Project.

[iii] The reserve margin is the amount of capacity a utility has available in excess of its system peak load, expressed in MW or as percentage of the peak.

[iv] Operating reserves are a combination of the unloaded capacity of plants that are connected to the system and have the ability to respond within ten minutes to changes in demand and capacity not operating but capable of providing power within ten minutes. Control areas dominated by hydro generation capacity have a lower operating reserve requirement closer to 5 percent.

[v] The WSCC is a voluntary organization comprised of major transmission utilities, transmission dependent utilities, and independent power producers/marketers within the western part of the continental U.S. the Canadian provinces of Alberta and British Columbia, and the northern portion of Baja California, Mexico. It promotes regional electric service reliability through the development of planning and operating reliability criteria and policies.

[vi] These sources included discussions with state regulatory agencies, energy industry newsletters (Western Energy Update, Power Markets Week, and the California Energy Markets), company web sites, and telephone calls to project developers.

Section III: New Market Entry

In this section, we compare our forecasts of annual MCPs to the annual revenue requirement of a new generator. The comparison provides a first order measure of whether prices are likely to be sufficient to attract new entry at a time when the system needs new generation capacity.

MCPs and system reliability are inextricably linked. To assure reliability, the revenue available from the PX energy market, as well as the ISO ancillary services markets, must be sufficient to sustain at least some of the existing generation infrastructure while attracting the additional generation investment needed to replace aging equipment and match load growth. The long-term price of electricity in a market-driven system should settle at a level just sufficient to pay for additional generation capacity, as it becomes needed. If the market is structured and working properly, electricity prices higher than a new generator's revenue requirement indicate new generation capacity is needed. Prices lower than the level needed to attract new investment should indicate a surplus of generation capacity exists.

Cost of a New Entrant

For new entry to occur, the MCP must be sufficient to recover the generator's fixed costs and variable costs of operation, including fuel costs. Fixed costs include the ongoing operation and maintenance (O&M) costs that are unavoidable, whether the plant operates or not (fixed O&M), plus the revenue that is required to provide a return to the debt and equity capital that finances construction. The cost of financing capital should provide lenders and investors with returns comparable to those available from other investments of similar risk.

The cost of building a new power plant depends on the technology employed and a host of other, often project/location-specific factors. As a majority of the projects proposed in California and the rest of the WSCC during the past two years have been 500 MW gas-fired combined cycle plants, the staff used the revenue requirement for a combined cycle plant as a proxy for the cost of new entry. For comparison purposes, the staff also developed the annual revenue requirement for a combustion turbine. **Table III-1** provides an estimate of the operating and cost characteristics for both a combined cycle and a combustion turbine.

Table III-1
Operating and Cost Assumptions
(Year 2000)

	Combined Cycle	**Combustion Turbine**
Fixed Costs		
Inputs to Fixed Charge Rate		
Debt/Equity Ratio	60/40	60/40
Return to Equity (post-tax)	17%	24%
Cost of Debt	8%	8%
Investment Recovery Period	30 years	30 years
Fixed Charge Rate (%)	**14.5%**	**18.5%**
Instant Capital Cost ($/kW)	600	360
Fixed O&M ($/kW-yr)	10	5
Variable Costs		
Heat Rate (Btu/kWh)	6,800	9,100
Fuel Cost ($/MMBtu)	2.5	2.5
Fuel Cost ($/MWh)	17	22.8
Variable O&M ($/MWh)	2	3
Total Variable Costs ($/MWh)	**19**	**25.8**

Source: California Energy Commission Staff Estimates

The upper half of **Table III-1** provides the assumptions and inputs used in calculating the revenue a plant needs to cover its annual fixed cost requirements. These costs are the product of the fixed charge rate times the instant capital cost plus fixed O&M. The fixed charge rate itself is determined by the following inputs:

debt/equity ratio,
the cost of debt,
the rate of return on equity,
the investment recovery period,
federal and state income tax rates, and
state sales and property tax rates.[i]

Using the assumptions in **Table III-1** yields a levelized annual fixed cost revenue requirement of $97/kW-yr for a combined cycle plant and $71.6/kW-yr for a combustion turbine.

(Fixed Charge Rate x Instant Capital Cost) + Fixed O&M = Fixed Cost Req.
Combined Cycle (0.145 x $600/kW) + $10/kW-yr = $97/kW-yr
Combustion Turbine (0.185 x $360/kW) + $5/kW-yr = $71.6/kW-yr

The bottom half of **Table III-1** contains the staff's assumptions that determine a new plant's variable operating costs. These include the plant's heat rate, cost of fuel, and variable O&M costs. Using the heat rates and variable O&M costs in **Table III-1** and a year 2000 fuel cost of $2.50/MMBtu[ii], the total variable cost of a combined cycle plant is $19.0/MWh and $25.8/MWh for a combustion turbine.

The annual average MCP that a power plant must receive to recover both its fixed annual revenue requirement and variable operating costs depends upon the amount of electricity it generates. A 500 MW power plant operating at full output level for 90 percent of the hours in the year can spread its fixed costs over 3,942 GWh. It, therefore, requires a lower average MCP to recover its costs than a plant that operates only 60 percent of the time. **Table III-2** indicates the annual average revenue requirement of a combined cycle plant and a combustion turbine operating at various capacity factors.

Table III-2
Annual Average Revenue Requirement
For New Generators at Various Capacity Factors
Year 2000

Capacity Factor (%)	($/MWh) Combined Cycle	Combustion Turbine
100%	30.06	33.90
95%	30.64	34.33
90%	31.29	34.81
85%	32.01	35.34
80%	32.82	35.94
75%	33.75	36.62
70%	34.80	37.40
65%	36.01	38.29
60%	37.43	39.34
55%	39.11	40.57
50%	41.12	42.06
45%	43.58	43.87
40%	46.65	46.13
35%	50.60	49.04
30%	55.86	52.93
25%	63.24	58.36
20%	74.30	66.51
15%	92.73	80.10
10%	129.59	107.28
5%	240.19	188.81

Table III-2 indicates that combined cycle plants, being more efficient but more expensive, have a better chance of recovering their revenue requirements than a combustion turbine if they can run 45 percent of the year or more. For fewer hours, combustion turbines are more cost effective.

Table III-3 shows how the annual average revenue requirement of a new combined cycle plant operating at a 90, 75, and 60 percent capacity factor escalates during the period 2000-2010. The annual average revenue requirement is sensitive not only to the plant's capacity factor but also to the assumptions contained in **Table III-1**. **Table III-4** illustrates how sensitive the revenue requirement of a generator is to small changes in some of the components underlying the plant's fixed and variable costs.

Table III-3
Necessary Annual Average Revenue Requirement
For a Combined Cycle Plant
(Nominal $/MWh)

Year	Capacity Factor		
	90%	75%	60%
2000	$31.3	$33.7	$37.4
2001	$31.9	$34.4	$38.1
2002	$32.3	$34.9	$38.7
2003	$33.4	$36.0	$40.0
2004	$34.5	$37.2	$41.2
2005	$35.6	$38.3	$42.4
2006	$36.7	$39.5	$43.7
2007	$37.9	$40.7	$45.0
2008	$39.1	$42.0	$46.4
2009	$40.5	$43.5	$48.0
2010	$42.0	$45.1	$49.7

Table III-4
Effect of Assumptions on Revenue Requirement
For a Combined Cycle in the Year 2000

Variable	Base Value	Alternative Value	Change in Annual Average Revenue Requirement ($/MWh)		
			90% CF	75% CF	60% CF
Return to Equity	17%	16%	($0.41)	($0.50)	($0.61)
Debt/Equity Ratio	60/40	50/50	$1.31	$1.57	$1.97
Capital Cost	$600	$610	$0.18	$0.22	$0.28
Recovery Period	30 Years	25 years	$0.42	$0.50	$0.63
Heat Rate	6,800MMBtu/kWh	6,700MMBtu/kWh	($0.25)	($0.25)	($0.25)
Gas Price	$2.50/MMBtu	$2.60/MMBtu	$0.68	$0.68	$0.68

Table III-4 shows that the cost of financing a project, the recovery period that the fixed costs are spread over and the fuel costs are factors which will weigh heavily in determining the plant's competitiveness in the market and its profitability. As the table shows, debt structure is highly significant. It can vary considerably among merchant generation firms.

As stated previously, cost parameters may vary by project and location; the fixed and variable cost values shown in **Table III-1** are intended to be representative of those faced by prospective new entrants in California. Variations would occur within the state due to local costs such as land, air emission offsets, water and natural gas. The staff notes that merchant plants which intend to serve California load, but lie outside the State, may have different construction costs and access to cheaper sources of natural gas than plants located within

California. Construction costs may differ in other states due to difference in the costs of land and labor, different requirements with respect to emission control technologies and offsets, and lead times.

Market Risk and the Cost of Capital

The cost of capital is a product of the perceptions of market risk and uncertainty that lenders and investors of capital in new power plants have regarding future market conditions. While a generator can minimize some of its market risk through long-term fuel contracts and contracts for direct sales of electricity to end-users, other sources of market risk are not so easily managed or contained. Some of these sources are described below.

Market-Risk

- The frequency and height of price spikes — periods during which generators can recover a substantial portion of their annual revenue requirements. Even generators with long-term contracts for sale of their output may rely on price spikes for an adequate revenue stream if the spikes affect the indices on which their contract prices are based.

- Development of the demand-side of the market and its effectiveness in moderating price volatility. The demand-side of the market includes demand-side bidding and the response of customers to real-time pricing tariffs, as well as the continuance of demand-side management (DSM) and direct load control management programs.

- The presence of price caps in both energy and ancillary service markets. The imposition of price caps may be necessary in the short term to stabilize the market while it matures; however, in the long term, these caps delay the price signals needed to trigger new plant investment.

Grid Planning Uncertainty

- Uncertainty regarding who will pay the congestion associated with additional generators.

- The mechanisms/process used to determine when upgrades to the transmission system will occur. The grid planning process is of concern to generators who anticipate revenue for alleviating local reliability problems, those who hope to benefit from constraints on imports into the area in which they are located, and those contemplating locating between major load centers and hoping to benefit from increases in transfer capability. A generator that can sell into the California market during the summer and the Northwest in the winter may have a better chance at making a profit. The risk, and associated financing costs, for projects with broad market access should, be lower.

Regulatory Uncertainty

- Changes in environmental regulations at the regional level, and at the national level (e.g., possible environmental legislation arising from the Kyoto protocol). Efforts to reduce greenhouse gas emissions by the 2008-2012 time frame may result in a reduction of coal-fired capacity in the WSCC. Coal represents 25 percent of the generation capacity in the WSCC.
- The pace of restructuring in neighboring states and the rules they adopt can affect the market clearing price in California. Generators located in states that have not restructured are guaranteed recovery of their fixed costs under the regulatory compact. These generators have a competitive advantage which allows them to bid surplus generation into the California market at their incremental cost of production. Also, because restructuring is occurring on a state-by-state basis, there are no uniform rules. Owners of existing plants may be required to divest these plants because of market power concerns. How each state decides to treat stranded asset costs will also influence the competitiveness of existing generators versus new generators.

In sum, building a new power plant is a risky undertaking. As the rest of the WSCC undergoes electricity restructuring and the competitive generation market matures, the uncertainty and risks associated with investment in power plants should diminish. This maturation of the market should translate into lower financing costs.[iii]

Other Revenue Sources

The estimates of the annual average revenue requirement provided in **Table III-2** and **III-3** are based on the assumption that the PX energy market is the sole source of revenue for a new entrant. The ISO's ancillary service markets and reliability must run (RMR) contracts, however, do represent potential sources of additional income for new generators. **Appendix D** of this report provides a detailed description of the ancillary services market and RMR contracts.

Ancillary services revenues may be important for the profitability of some generators and may constitute a larger percentage of revenues in some months, as demonstrated in **Table III-5**.

Table III-5
Monthly Ancillary Service Costs
As A Percent of Monthly PX Energy Costs*

Jan-99	8.1%	Jul-99	8.1%
Feb-99	5.8%	Aug-99	5.3%
Mar-99	7.8%	Sep-99	4.3%
Apr-99	8.5%	Oct-99	4.6%
May-99	9.5%	Nov-99	3.1%
Jun-99	8.7%	Dec-99	1.8%

***Monthly ISO Ancillary Services Cost/Monthly PX Energy Cost
Source: Management Report Overview Presentation for the ISO 2/24/00 Board Meeting

For the period April through December 1999, the ISO reported that ancillary service costs averaged about $1.87/MWh of total system load served, or about 5.6 percent of total market energy costs.[iv] Using historical data to quantify the amount of income that new entrants might expect from the provision of ancillary services would be imprudent, given both the immaturity of the market, which has only been operating since April 1998, and an unseasonably mild summer in 1999. Future revenues are all the more uncertain due to ongoing changes in the rules governing the procurement of ancillary services. Finally, most of the ancillary services require that the generator have unloaded capacity - the exception being when there is more generation than load (downward regulation). If a new market entrant were bidding into the ancillary services market, the revenue would come at the expense of revenue from the energy market.

Reliability Must-Run (RMR) contracts or, more generally, payments to ensure availability to meet local reliability requirements, may provide some new entrants with revenue beyond that earned in the energy and ancillary service markets.[v] RMR contracts are intended to help generators in areas with a local reliability requirement recover a portion of their fixed costs to ensure their availability. The portion of a generator's costs covered under an RMR contract is negotiated and depends in part upon the generator's expected profitability in the PX energy and ISO ancillary services markets. Accordingly, some new plants that are unable to recover their fixed costs from these markets, may, under the terms of an RMR contract, be paid a portion of the difference between the MCP and their revenue requirement.

The ISO has proposed providing a floor payment to attract new generators to areas with local reliability constraints. For example, the ISO would pay new generators locating in such an area the lesser of $25/kW-yr or10 percent of their annual fixed revenue requirement, even if the plant is profitable based on its revenue from the energy and ancillary services markets.[vi] For a new combined cycle plant operating at a 90 percent capacity factor, this floor payment would lower its annual average revenue requirement year by $1.23/MWh.[vii]

The remaining revenue option available to new generators is a negotiated direct sale to an end-user. There is already some evidence that new generators locating in the California market are trying to firm up their expected revenue by directly contracting with end users.

By guaranteeing a portion or all of their revenue through a direct access contract, a generator can reduce their risk and, consequently, their financing costs.

Viability of New Market Entry Under Staff's Scenarios

Staff examined how new combined cycle plants would fare under the staff's two alternative resource scenarios. **Table III-6** compares the annual average MCP under the two resource development scenarios to the estimated annual average revenue requirement of a new combined cycle plant operating at a 90 percent capacity factor from **Table III-3.** The new entrant's revenue requirement has been reduced by 5 percent on the assumption that at least 5 percent of a new market entrant's revenue would come from sources outside of the PX energy market. As **Figure III-1** illustrates, under the staff's resource scenarios, a new market entrant would not be able to cover their annual revenue requirement until 2010.

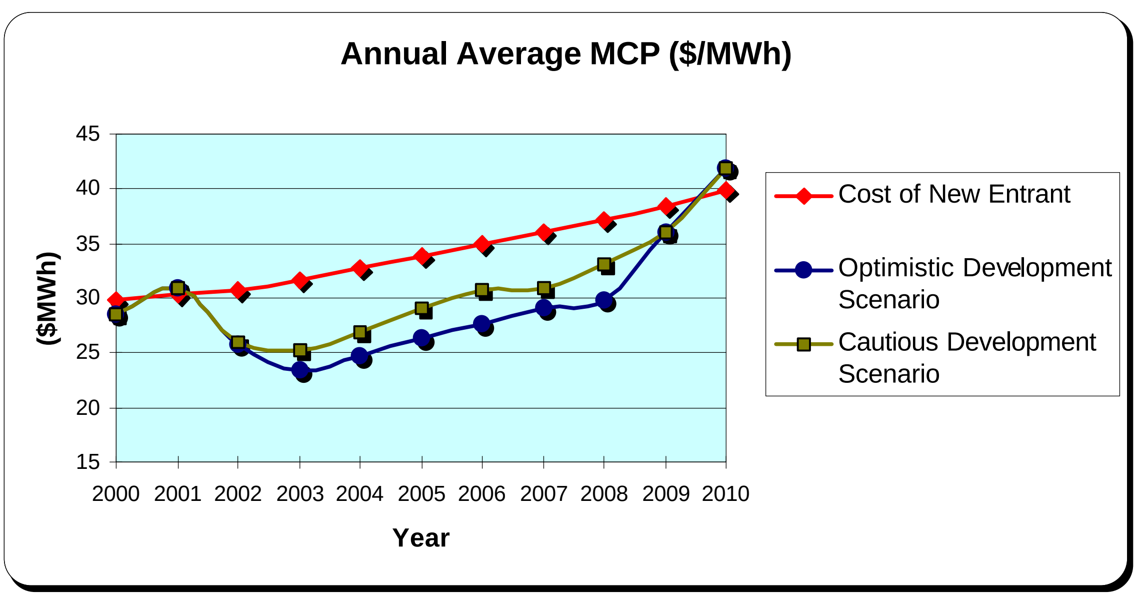
The staff acknowledges that some of the assumptions that went into our modeling of the PX market have both a high degree of uncertainty and a significant influence on market clearing prices. These include our assumption that the generators' bidding behavior in the future will mimic what has occurred historically, and that the nuclear plants will continue to operate. It is also highly unlikely that the timing and number of new generators coming online will occur exactly as portrayed in either scenario.

Despite the uncertainty of these assumptions, we believe that our modeling results illustrate important trends that will have significant consequences to future system reliability. One trend is that future generation resource additions will not occur in a smooth, even manner, but will more likely occur in a cyclical pattern resulting in periods of excess and lean generation capacity. MCPs will respond accordingly, fluctuating in a cyclical pattern as well. This cyclical pattern of development will occur primarily because the profitability of the new generators depends in large part on the prices they are able to get during summer peak demand season. The staff's modeling indicates that MCPs during the summer peak demand season will not reach a level to support new entry until reserve margins drop below the levels usually regarded as necessary for reliable service.

Table III-6
Comparison of Revenue Requirement of a New Market Entrant To Resource Development Scenarios Annual Average MCPs

Year	Optimistic Development Scenario ($/MWh)	Cost of New Entrant ($/MWh)	% Diff	Cautious Development Scenario ($/MWh)	Cost of New Entrant ($/MWh)	% Diff
2000	28.5	29.7	-4%	28.5	29.7	-4%
2001	31.0	30.3	2%	31.0	30.3	2%
2002	25.9	30.7	-16%	25.9	30.7	-16%
2003	23.4	31.7	-26%	25.3	31.7	-20%
2004	24.8	32.8	-24%	26.9	32.8	-18%
2005	26.3	33.8	-22%	29.1	33.8	-14%
2006	27.7	34.9	-21%	30.7	34.9	-12%
2007	29.1	36.0	-19%	31.0	36.0	-14%
2008	29.9	37.1	-19%	33.2	37.1	-11%
2009	36.0	38.5	-7%	36.0	38.5	-7%
2010	41.9	39.9	5%	41.9	39.9	5%

Figure III-1
Comparison of Revenue Requirement of a New Market Entrant To Resource Development Scenarios Annual Average MCPs



This pattern of periodic cycles of excess and under capacity is typical of most capital intensive industries. Excess production capacity in most competitive industries, however, is undesirable because it depresses prices and makes it more difficult for all competitors within that industry to make a profit.

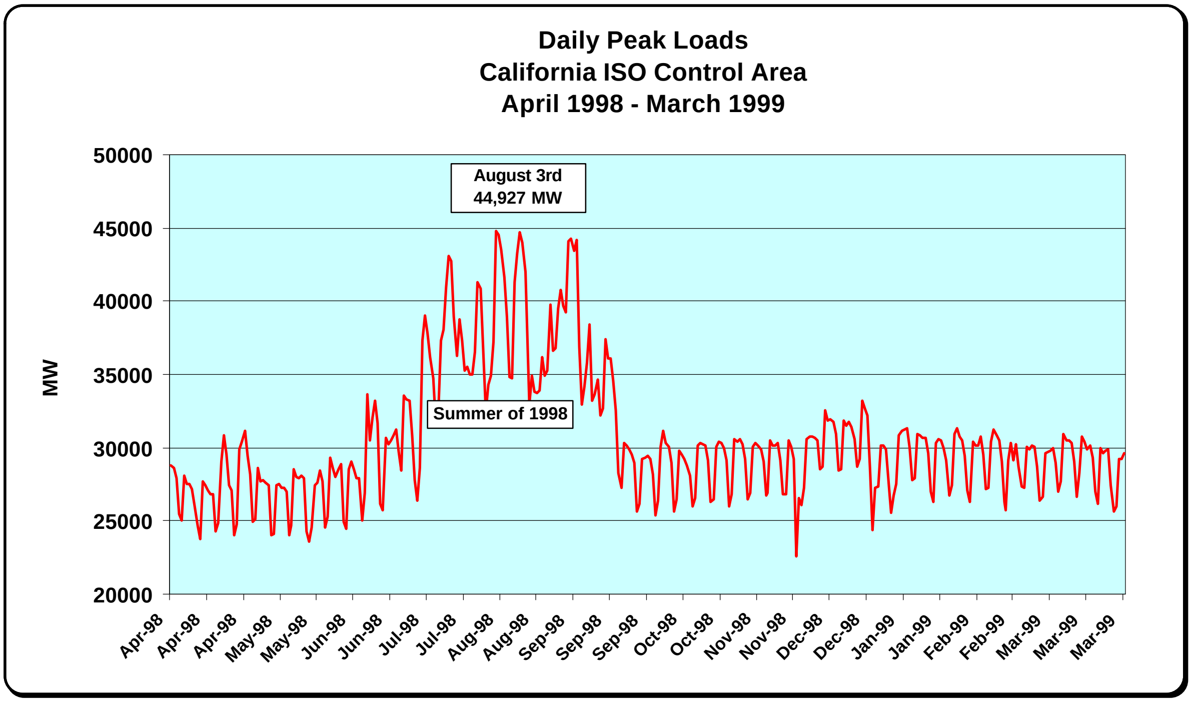
At the time of peak demand, which may last for only a few hours every year, the minimum reserve capability to maintain system reliability is 7 percent.[viii] For most hours of the year, a rather substantial amount of production capacity is not being used. **Table III-7** and **Figure III-2** illustrate this point. **Table III-7** provides the 1998 monthly operating and planning reserve margins over firm loads[ix] for the California-Mexico reliability region of the WSCC. **Figure III-2** depicts the ISO daily loads for one year.

Table III-7
California-Mexico Power Area Actual Monthly Margins for 1998

Month	Jan	Feb	Mar	Apr	May	Jun
Firm Peak Demand (MW)	36,691	35,885	35,561	37,334	33,886	41,909
(Available Capacity - Monthly Peak) (MW)	9,840	11,157	9,300	13,839	15,475	14,224
Operating Margin Over Firm Loads	**26.8%**	**31.1%**	**26.2%**	**37.1%**	**45.7%**	**33.9%**
MW Unavailable (Inoperable, Forced Out, Maintenance)	8,170	8,110	10,217	5,094	4,569	1,959
Planning Margin Over Firm Loads	**49.1%**	**53.7%**	**54.9%**	**50.7%**	**59.2%**	**38.6%**
Month	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Firm Peak Demand	49,857	54,586	53,423	40,667	35,982	38,304
Margin Over Firm Loads - MW (Available Capacity – Monthly Peak)	6,616	4,323	4,480	12,327	15,880	12,993
Operating Margin Over Firm Loads	**13.3%**	**7.9%**	**8.4%**	**30.3%**	**44.1%**	**33.9%**
MW Unavailable (Inoperable, Forced Out, Maintenance)	1,549	716	537	3,293	4,739	4,871
Planning Margin Over Firm Loads	**16.4%**	**9.2%**	**9.4%**	**38.4%**	**57.3%**	**46.6%**

Source: Western Systems Coordinating Council, “10-Year Coordinated Plan Summary 1999-2008,” October 1999.

Figure III-2



The problem with relying on summer peak demand prices to signal when new entry will occur is that it is largely dependent on weather. The past two summers illustrate that summer demands can fluctuate greatly from one year to the next. In 1998, there were 120 hours when the California ISO peak loads were over 40,000 MW. In 1999, the ISO's loads were over 40,000 MW for only 48 hours.[x] And, as the demand market matures, it is in the highest price hours that we expect to see demand elasticity to take hold.

To attract new market entry, MCPs during the summer peak demand season will have to reach a level high enough to compensate for all the low prices that prevail during most of the year because of an excess of capacity. The staff's modeling indicates that MCPs will only reach that level when the reserve margins during the summer are below the level needed to ensure reliable service.

Any reduction in reliability due to declining reserve margins is arguably a transitional market problem arising from the current inability of consumers to respond to real-time prices. If consumers are willing to pay high prices for energy during peak hours, MCPs should be sufficiently high so as to ensure reliable service. If consumers react to high prices by reducing consumption, declining peak loads will offset the relative absence of generation capacity.

Certainly, if all of the plants in the staff's scenario analysis come on line supply adequacy will not be a problem. However, the staff believes that developers will be closely watching MCPs to see how the prices respond to new entry. If MCPs in 2002 behave in a manner consistent with the results of the staff's modeling as a result of new capacity additions, subsequent additions could be even fewer and more spread out than the additions assumed in the staff's cautious development scenario.

Future Work

The staff recognizes that in the new competitive electricity market, reliability is no longer a matter of new generation capacity being built to meet a forecasted level of demand plus a reserve requirement. Both supply- and demand-side markets need to be developed to ensure a reliable electricity system. In order for these markets to develop there must be clear price signals that indicate what consumers are willing to pay for reliability. Deregulation, however, is still in its infancy in California and the rest of the WSCC. Market imperfections are still being identified and solutions implemented so that both new power plant developers and electricity consumers receive accurate market signals and, from the consumer's standpoint, have the capability to respond to them. In future studies, the staff intends to investigate the impact of greater demand-side market responsiveness in more detail.

In upcoming studies, staff will assess the impact of dry hydroelectric conditions, retirement of older units, and potential demand-side initiatives to reduce summer peaks.

[i] Federal and State marginal income tax rates are 35 percent and 11 percent, respectively; state sales tax rate is 7.5 percent, state property tax rate is 1 percent. Other factors that influence the fixed charge rate are the federal and state depreciation schedules used.

[ii] See Appendix A for natural gas price forecast.

[iii] A drop in the required return on equity from 17 percent to 12 percent would lower the annual revenue requirement in 2001 of a new combined cycle plant, operating at a 90 percent capacity factor, from $31.29/MWh to $29.29/MWh, a decrease of six percent.

[iv] Attachment A to Memorandum from Anjali Sheffrin to Market Issues/ADR Committee, January 13, 2000, regarding Market Analysis Report, page 5.

[v] Local reliability constraints determine the amount of an area's load that must be met by local generation. For example, the San Francisco peninsula has a local reliability requirement that specifies that 50 percent of the area's peak demand be met with local generation.

[vi] California Independent System Operator, *Multi-Year Reliability Must-Run RFP*, June 24, 1999.

[vii] MWh of Generation @ 90 percent Capacity Factor
(500 MW x .9 x 8,760 hrs.) = 3,942,000 MWh
Fixed Cost Revenue Requirement without ISO incentive payment
($97/kW-yr x 500 MW x 1000)/3,942,000 MWh = $12.30/MWh
Fixed Cost Revenue Requirement with ISO incentive payment
(($97/kW-yr - $9.7/kW-yr) x 500 MW x1000)/3,942,000MWh = $11.07/MWh
Reduction in Fixed Cost Revenue Requirement
($12.30/MWh - $11.07/MWh) = $1.23/MWh

[viii] Under regulation, utilities typically built out their systems to ensure a planning reserve of around 13 percent. This figure allowed them to cover contingencies such as forced outages and forecast error.

[ix] Firm load excludes the demand of customers who receive electricity under an interruptible load tariff.

[x] Attachment A to Memorandum from Anjali Sheffrin to Market Issues/ADR Committee, January 13, 2000, regarding Market Analysis Report, page 2.

Endnotes

1. All MCPs referred to in this report are for the PX's hourly day ahead unconstrained market and unweighted by load.

2. Until March 2002, California's investor-owned utilities (PG&E, SCE, and SDG&E) must buy from and sell all of their generation through the California Power Exchange (PX), which will auction electric power demand and supply. Other market participants — such as independent power producers (IPPs), municipal generators, and utilities located outside of California, aggregators, etc. — have the option of buying from, or selling electricity through the PX or selling directly to a customer without going through the PX.

3. The MCPs from the staff's two scenarios were outputs of the Multisym™ model, a licensed product of Henwood Energy Services Inc. Multisym™ emulates the hourly bidding market of the California PX, as well as the commitment and dispatch of generators and the transmission of electricity throughout the WSCC reliability region.

4. See Appendix D, "Hourly MCP Scaling Methodology," in 1998 Market Clearing Price Forecast for the California Market: Forecast Methodology & Analytical Issues, California Energy Commission, December 1998, Publication No. 300-98-015.

5. On August 26, 1999, the ISO Board of Governors approved the creation of a new congestion zone between Path 15 and Path 26. This third zone is defined as the central California zone in staff's modeling.

6. These included System Impact Studies for the La Paloma Power Project, the Sunrise Cogeneration and Power Project, the Elk Hills Power Project, the Pittsburg District Energy Facility, Delta Energy Center Project, the Morro Bay Power Plant Modernization and the Moss Landing Power Plant Project.

7. The reserve margin is the amount of capacity a utility has available in excess of its system peak load, expressed in MW or as percentage of the peak.

8. Operating reserves are a combination of the unloaded capacity of plants that are connected to the system and have the ability to respond within ten minutes to changes in demand and capacity not operating but capable of providing power within ten minutes. Control areas dominated by hydro generation capacity have a lower operating reserve requirement closer to 5 percent.

9. The WSCC is a voluntary organization comprised of major transmission utilities, transmission dependent utilities, and independent power producers/marketers within the western part of the continental U.S. the Canadian provinces of Alberta and British Columbia, and the northern portion of Baja California, Mexico. It promotes regional electric service reliability through the development of planning and operating reliability criteria and policies.

10. These sources included discussions with state regulatory agencies, energy industry newsletters (Western Energy Update, Power Markets Week, and the California Energy Markets), company web sites, and telephone calls to project developers.

11. Federal and State marginal income tax rates are 35 percent and 11 percent, respectively; state sales tax rate is 7.5 percent, state property tax rate is 1 percent. Other factors that influence the fixed charge rate are the federal and state depreciation schedules used.

12. See Appendix A for natural gas price forecast.

13. A drop in the required return on equity from 17 percent to 12 percent would lower the annual revenue requirement in 2001 of a new combined cycle plant, operating at a 90 percent capacity factor, from $31.29/MWh to $29.29/MWh, a decrease of six percent.

14. Attachment A to Memorandum from Anjali Sheffrin to Market Issues/ADR Committee, January 13, 2000, regarding Market Analysis Report, page 5.

15. Local reliability constraints determine the amount of an area's load that must be met by local generation. For example, the San Francisco peninsula has a local reliability requirement that specifies that 50 percent of the area's peak demand be met with local generation.

16. California Independent System Operator, Multi-Year Reliability Must-Run RFP, June 24, 1999.

17. MWh of Generation @ 90 percent Capacity Factor
    (500 MW x .9 x 8,760 hrs.) = 3,942,000 MWh
    Fixed Cost Revenue Requirement without ISO incentive payment
    ($97/kW-yr x 500 MW x 1000)/3,942,000 MWh = $12.30/MWh
    Fixed Cost Revenue Requirement with ISO incentive payment
    (($97/kW-yr - $9.7/kW-yr) x 500 MW x1000)/3,942,000MWh = $11.07/MWh
    Reduction in Fixed Cost Revenue Requirement
    $12.30/MWh - $11.07/MWh) = $1.23/MWh

18. Under regulation, utilities typically built out their systems to ensure a planning reserve of around 13 percent. This figure allowed them to cover contingencies such as forced outages and forecast error.

19. Firm load excludes the demand of customers who receive electricity under an interruptible load tariff.

20. Attachment A to Memorandum from Anjali Sheffrin to Market Issues/ADR Committee, January 13, 2000, regarding Market Analysis Report, page 2.

21. For a more detailed description of the staff's gas price forecast see, "Staff's Preliminary Natural Gas Price and Production Forecast: Assumptions and Results" on the Commission Web Site at www.energy.ca.gov/naturalgas/1999-11-16_GAS_BASECASE.PDF

22. 1998 Market Clearing Price Forecast for the California Market: Forecast Methodology & Analytical Issues, Staff Report, California Energy Commission, December 1998, CEC Publication No. P300-98-015. Also available at the Commission's Web Site. (www.energy.state.ca.gov/electricity).

23. Ibid

24. Ibid, Appendix D, Page 43.

25. In some cases, preferred generator dispatch schedules may not be a matter only of preference. Physical design of a package of generating plants may preclude them from operating or responding to operational commands individually.

26. At this point, suppliers and purchasers also include any bids to supply ancillary services.

27. See discussion of congestion below.

28. A minimum contract unit is for delivery of a one MW of energy for sixteen hours a day during a month. This translates into either 400 or 416 MWh/month (16 hrs* 25 days or 26 days = 400 MWh or 416 MWh).

29. See Replacement Reserves and Automated Generation Control below. Major or sustained deviations from schedule may be substantial enough that these plants cannot compensate without compromising regulating margins, necessitating an additional market to compensate for these larger deviations from schedule.

30. In this context, "adequate" means within standards set by the WSCC.

31. Transmission system equipment—such as shunt capacitors, can sometimes be used to maintain voltage and reactive power; however, in some cases, the use of non-generation equipment is impractical or cost-prohibitive.

32. Expected software enhancements will eventually allow other generators to compete to provide these services.

Appendix A: Preliminary 1999 Fuels Report Gas Price Forecast

This appendix provides the natural gas prices used in the 2000 MCP forecast along with a comparison to the gas prices used in the staff's December 1998 MCP forecast. A brief discussion of the methodology underlying the development of the gas prices is also provided.[i]

Natural Gas Prices for the Electricity Generation Sector

Table A-1 contains the forecast of the price of natural gas to the electricity generation sector in nominal dollars and constant 1998 dollars per million Btu for each of the natural gas service areas in California. The price includes transportation charges.

Table A-1
California Energy Commission
Preliminary FR99 Gas Price Forecast
(November 22, 1999)

	Nominal $/MMBtu				Deflators	1998 $/MMBtu				
YEAR	PG&E	SCG	SDG&E	COOL-WATER	Feb-99	YEAR	PG&E	SCG	SDG&E	COOL-WATER
1998	2.57	2.89	2.75		1.0000	**1998**	2.57	2.89	2.75	
1999	2.65	2.66	2.84		1.0181	**1999**	2.60	2.61	2.79	
2000	2.54	2.48	2.77	2.34	1.0385	**2000**	2.45	2.39	2.66	2.26
2001	2.58	2.51	2.80	2.37	1.0623	**2001**	2.43	2.36	2.64	2.23
2002	2.58	2.53	2.84	2.40	1.0864	**2002**	2.38	2.33	2.61	2.21
2003	2.69	2.65	3.02	2.49	1.1101	**2003**	2.42	2.39	2.72	2.25
2004	2.79	2.77	3.12	2.60	1.1389	**2004**	2.45	2.43	2.74	2.29
2005	2.89	2.88	3.23	2.70	1.1587	**2005**	2.49	2.49	2.79	2.33
2006	3.00	3.00	3.34	2.80	1.1865	**2006**	2.53	2.53	2.82	2.36
2007	3.12	3.11	3.48	2.91	1.2162	**2007**	2.56	2.56	2.86	2.40
2008	3.24	3.22	3.61	3.03	1.2482	**2008**	2.60	2.58	2.89	2.43
2009	3.38	3.37	3.76	3.15	1.2830	**2009**	2.63	2.62	2.93	2.46
2010	3.52	3.52	3.89	3.29	1.3209	**2010**	2.66	2.66	2.95	2.49
2011	3.68	3.68	4.06	3.45	1.3623	**2011**	2.70	2.70	2.98	2.53
2012	3.85	3.86	4.26	3.62	1.4061	**2012**	2.74	2.75	3.03	2.57
2013	4.04	4.06	4.47	3.79	1.4529	**2013**	2.78	2.80	3.08	2.61
2014	4.25	4.28	4.70	3.97	1.5022	**2014**	2.83	2.85	3.13	2.64
2015	4.47	4.52	4.95	4.18	1.5562	**2015**	2.87	2.90	3.18	2.68
2016	4.71	4.77	5.20	4.40	1.6150	**2016**	2.92	2.95	3.22	2.72
2017	4.98	5.04	5.48	4.64	1.6782	**2017**	2.97	3.00	3.27	2.76
2018	5.26	5.33	5.79	4.73	1.7464	**2018**	3.01	3.05	3.32	2.71
2019	5.58	5.66	6.05	4.84	1.8211	**2019**	3.06	3.11	3.32	2.66

The preliminary forecast shows a slight increase in the nominal price of natural gas for power generation customers over the next five years. In real dollars, however, a short term decline in the price of gas occurs until 2002. A significant decline in the price of gas in SoCal Gas service area occurs where the forecast shows prices in the year 2000 to be $0.41 per MMBtu lower than the historical 1998 price in nominal dollars. Much of this decline is due to a reallocation of distribution costs among customers by SoCal Gas. By 2005, SoCal Gas prices are comparable to PG&E's. SDG&E's power generation gas prices, however, remain $0.30 to $0.45 per MMBtu higher in nominal dollars than the other service area prices throughout the forecast. The SDG&E forecast assumes that the California Public Utilities Commission continues with its current policy for passing SoCal Gas instate transport costs through to SDG&E. In SoCal's current ongoing rate case proceedings, many parties are arguing for the same electricity generation natural gas rates for SoCal Gas and SDG&E service areas. The outcome of these proceedings could results in gas prices being significantly different from the preliminary forecast.

Figure A-1 below illustrates the natural gas price forecasts for each of the major utility service areas in real dollars. **Figure A-2** shows the same forecasts in nominal dollars.

Figure A-1

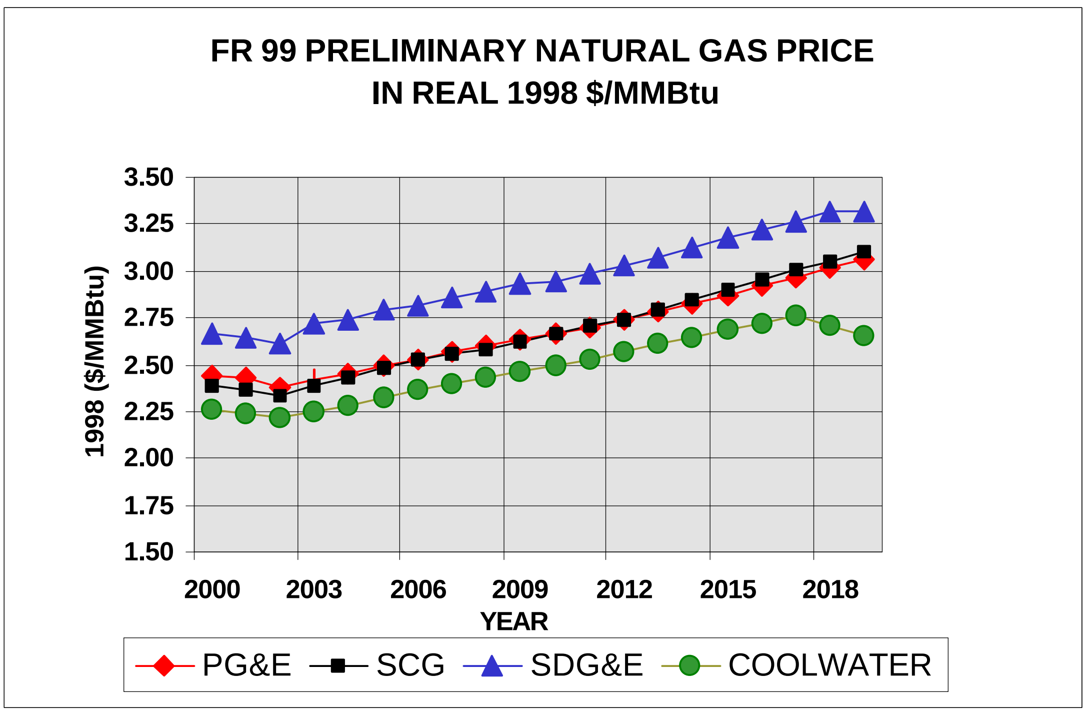
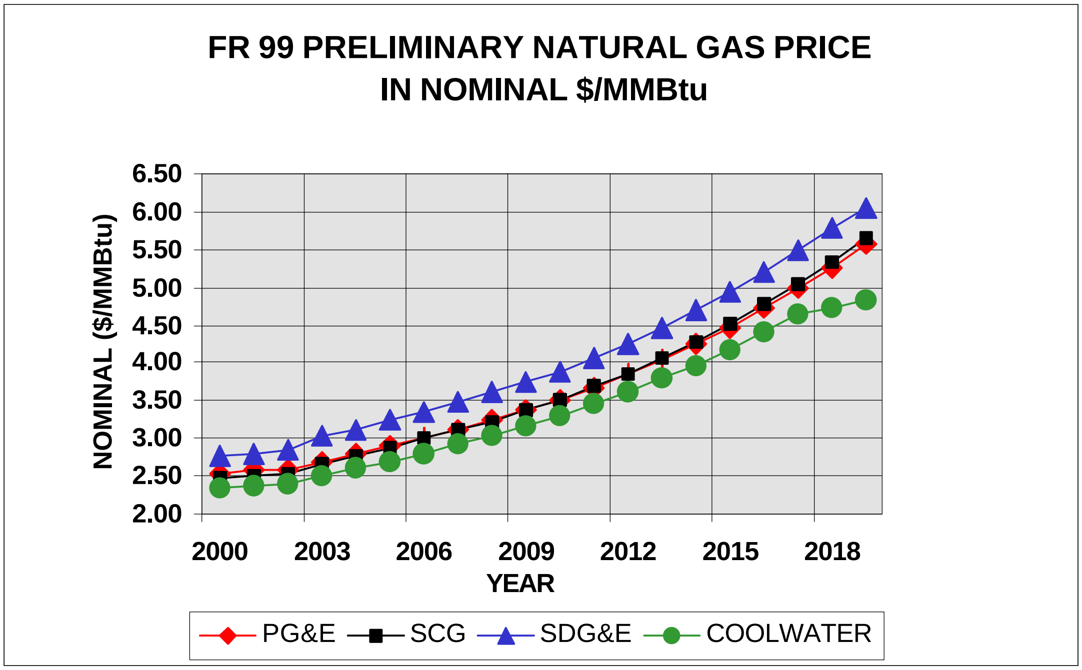


Figure A-2



Comparison to Previous Forecast

Table A-2 provides a comparison of the ***Final Fuels Report (FR 97) Gas Price Forecast***, March 18, 1998 used in the staff's 1998 market clearing price forecast[ii] to the Preliminary ***FR 99*** forecast used in this 2000 market clearing price forecast. The ***FR 99*** forecast prices are significantly higher in the early years compared to the ***FR 97*** forecast. The difference between the two forecasts is attributable to the divestiture of the California investor-owned utility (IOU) fossil fuel-fired power plants.

The methodology underlying the ***FR 97*** forecast assumed that the California IOUs retained ownership of their fossil fuel-fired power plants. The divestiture of these plants affected certain assumptions within the new ***FR 99*** forecast. First, the utilities' revenue allocation formula changed to recover more from electric generation customers. Second, it is assumed that the natural gas supply pool that the divested plants have access to is more expensive than the pool the California IOUs had access to when they owned the plants. When the utilities sold their fossil fuel-fired plants, the remaining contracts for firm interstate gas pipeline capacity were assumed to be no longer applicable.

Table A-2
Comparison of Gas Price Forecasts
Nominal $/MMBtu

Year	PG&E		Change	SCG		Change	SDG&E		Change
	Nov-99	Mar-98		Nov-99	Mar-98		Nov-99	Mar-98	
2000	2.54	2.19	16.1%	2.48	2.17	14.4%	2.77	2.61	6.1%
2001	2.58	2.28	13.1%	2.51	2.29	9.7%	2.80	2.73	2.8%
2002	2.58	2.38	8.4%	2.53	2.40	5.4%	2.84	2.85	-0.5%
2003	2.69	2.50	7.5%	2.65	2.55	4.0%	3.02	2.98	1.6%
2004	2.79	2.62	6.7%	2.77	2.69	2.9%	3.12	3.13	-0.3%
2005	2.89	2.75	5.0%	2.88	2.85	1.2%	3.23	3.28	-1.4%
2006	3.00	2.89	3.8%	3.00	3.00	0.1%	3.34	3.43	-2.6%
2007	3.12	3.03	2.9%	3.11	3.17	-2.0%	3.48	3.61	-3.6%
2008	3.24	3.18	2.0%	3.22	3.38	-4.6%	3.61	3.81	-5.4%
2009	3.38	3.34	1.2%	3.37	3.57	-5.6%	3.76	3.99	-5.9%
2010	3.52	3.51	0.2%	3.52	3.69	-4.7%	3.89	4.14	-5.9%
2011	3.68	3.70	-0.8%	3.68	3.90	-5.7%	4.06	4.36	-6.8%
2012	3.85	3.91	-1.6%	3.86	4.12	-6.4%	4.26	4.58	-7.1%
2013	4.04	4.13	-2.1%	4.06	4.35	-6.7%	4.47	4.82	-7.3%
2014	4.25	4.36	-2.4%	4.28	4.59	-6.7%	4.70	5.06	-7.1%
2015	4.47	4.59	-2.5%	4.52	4.83	-6.6%	4.95	5.31	-6.9%
2016	4.71	4.83	-2.4%	4.77	5.10	-6.4%	5.20	5.59	-6.9%
2017	4.98	5.09	-2.2%	5.04	5.37	-6.1%	5.48	5.86	-6.5%

Gas Price Forecast Methodology

The California Energy Commission's Fuel Resources Office uses the North American Regional Gas (NARG) model to forecast natural gas prices for various market sectors such as electric generation. The NARG model is a generalized equilibrium model that simultaneously solves for supply, demand and price equilibrium for 19 North American supply and demand regions.

Basic inputs to the NARG model include estimates of resource availability, production costs, pipeline capacity and transportation costs, regional demand projections, and other parameters defining market fundamentals. The model also accounts for reserve appreciation over time. The model uses these inputs to determine the California border price of gas. In determining the end-use price for each market sector in the state, the model tracks the costs of distributing and delivering natural gas for each customer class. These costs are added to the California border price to generate the end-use prices for each market sector in each natural gas service region within the state.

During the 2002-2022 forecast horizon, natural gas supplies for California are expected to come from several sources. Natural gas from the Southwest is expected to remain the principal source during the next 20 years, accounting for approximately 45 percent of total statewide requirements. The remainder of the State's gas demand will be met from supplies from the Rocky Mountain region, Canada, and in-state producers. The staff expects border prices to increase 1.7 percent per year from $2.02 per MCF in 2002 to $2.86 per MCF in the year 2022 (prices expressed in constant 1998 dollars). The details on the estimated source of supply and border price are provided in **Table A-3**.

Table A-3
California Border Supply Availability and Price
1999 Preliminary Base Case

Producing Region	1997	2002	2007	2012	2017	2022
Production (TCF):						
California	0.297	0.292	0.358	0.363	0.383	0.401
Southwest	0.885	1.016	1.131	1.159	1.150	1.157
Rocky Mountains	0.232	0.272	0.319	0.341	0.360	0.380
Canada	0.599	0.528	0.573	0.617	0.678	0.731
Total Supply Available to California (TCF)	**2.012**	**2.108**	**2.381**	**2.480**	**2.570**	**2.669**
Price (1998$/MCF)						
California	N/A	2.13	2.30	2.50	2.70	2.91
Southwest	N/A	2.02	2.25	2.45	2.68	2.91
Rocky Mountains	N/A	2.10	2.32	2.52	2.74	2.96
Canada	N/A	1.96	2.13	2.30	2.50	2.71
Average Price at California Border (1998$/MCF)	**N/A**	**2.02**	**2.23**	**2.42**	**2.64**	**2.86**

While the border price of gas is expected to increase over time, the distribution costs drop for all end-use sectors, thus offsetting the commodity price increase and providing for a relatively flat forecast of natural gas prices in real (not adjusted for inflation) dollars. For the core sector (residential, commercial and small industrial customers), the distribution costs drop at a faster rate than the increase in commodity costs. Therefore, core prices decrease slightly in real terms. On the other hand, the noncore sector (large industrial and electric generation customers) see commodity prices rise faster than the distribution costs decline, which provides a slight growth in noncore customer prices over the forecast horizon

[i] For a more detailed description of the staff's gas price forecast see, "Staff's Preliminary Natural Gas Price and Production Forecast: Assumptions and Results" on the Commission Web Site at www.energy.ca.gov/naturalgas/1999-11-16_GAS_BASECASE.PDF .

[ii] *1998 Market Clearing Price Forecast for the California Market: Forecast Methodology & Analytical Issues*, Staff Report, California Energy Commission, December 1998, CEC Publication No. P300-98-015. Also available at the Commission's Web Site. (www.energy.state.ca.gov/electricity).

Appendix B: MCP Forecast and PX Price Comparisons

This appendix compares the Energy Commission staff's previous Market Clearing Price (MCP) forecast (December 1998) to the actual PX prices of the California electricity market and examines the factors that contributed actual MCPs being significantly different from our forecasted prices.

Comparison of 1998 Forecast to PX Prices

Table B-1 compares the monthly values of the Energy Commission staff's December 1998 MCP Forecast[i] to actual PX prices, from the beginning of the market, April 1998, up through December of 1999.

Table B-1
1998 MCP Forecast vs. Actual PX Prices

1998	PX Actual ($/MWh)	CEC Dec-98 ($/MWh)	1999	PX Actual ($/MWh)	CEC Dec-98 ($/MWh)
Jan	-	-	Jan	21.0	27.5
Feb	-	-	Feb	19.0	24.8
Mar	-	-	Mar	18.8	23.6
Apr	22.6	21.0	Apr	24.0	21.3
May	11.6	20.0	May	23.6	19.9
Jun	12.1	19.2	Jun	23.5	18.4
Jul	32.4	27.3	Jul	28.9	24.8
Aug	39.5	30.1	Aug	32.3	33.1
Sep	34.0	30.5	Sep	33.9	29.8
Oct	26.6	24.8	Oct	47.6	22.7
Nov	25.7	26.0	Nov	37.0	23.7
Dec	29.1	29.0	Dec	29.7	26.7
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Average	26.0	25.3	Average	28.4	24.7

The PX monthly prices are the unconstrained average MCP, unweighted by demand. The PX monthly values are calculated as the simple average of all the hours in the month. The Energy Commission forecast is the simple average of the hours in a typical week. For both the PX prices and the staff's forecast, the annual averages are weighted by the days in the month.

The following two figures present the data in **Table B-1** graphically. **Figure B-1A** compares the Energy Commission staff's forecast to the actual PX prices for the year 1998. **Figure B-1B** makes this same comparison for the year 1999.

Figure B-1A

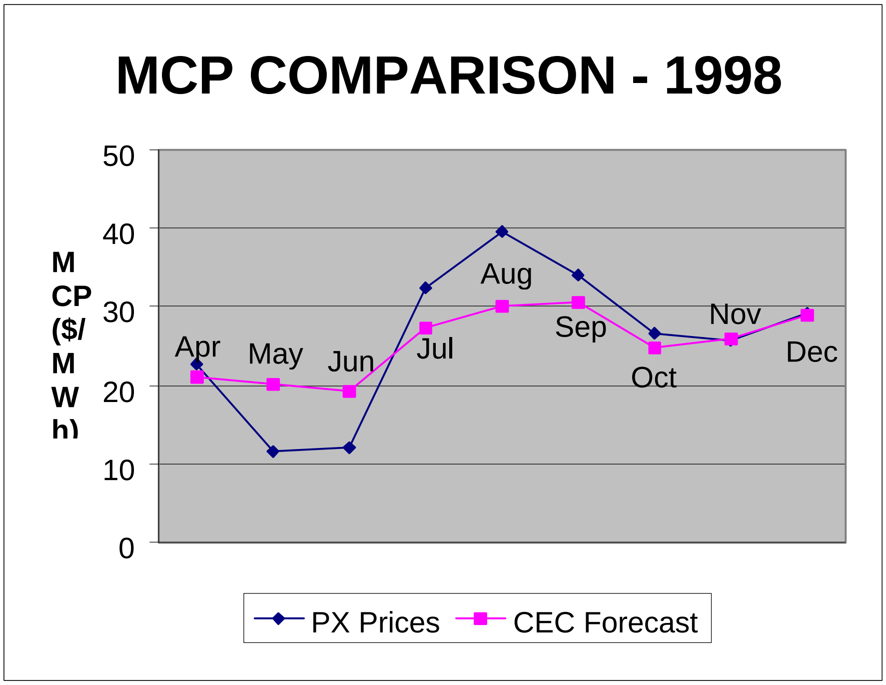
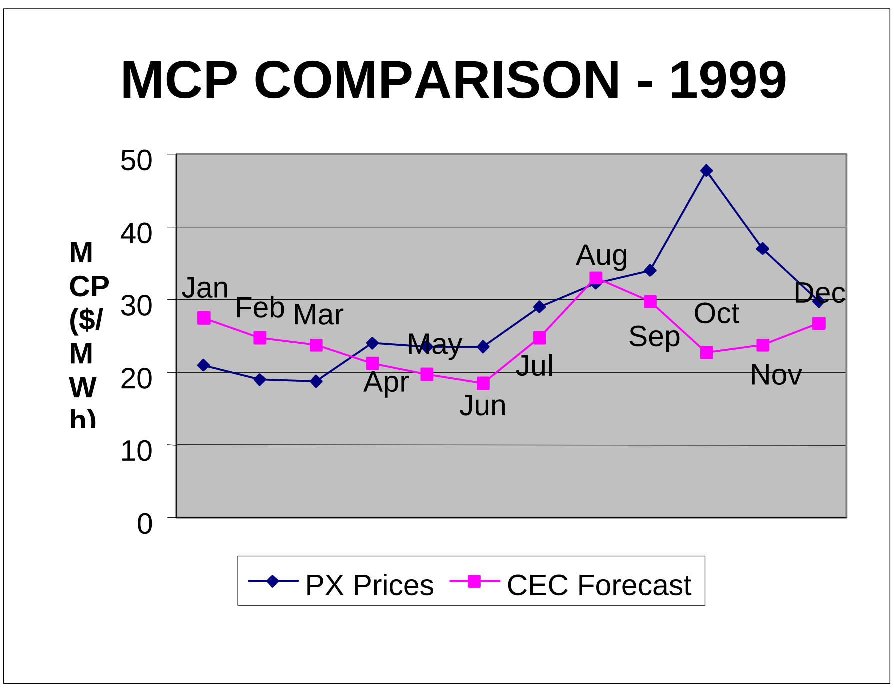


Figure B-1B



The 1998 MCP Forecast is more than 10 percent higher or lower than the actual PX prices for 16 of the 21 months. These differences are largely traceable to the fact that the forecast is for an average year: average temperatures, average hydroelectric generation and average equipment failures. In the real world, there are few – if any – "average" months. In addition, actual monthly natural gas prices often deviate from the Commission's gas price forecast, which further compounds these differences in MCPs. For example, the low spring PX prices reflect the above average hydro conditions that have characterized 1998 and 1999, in some cases aggravated by lower than average temperatures and/or low gas prices. The high summer PX prices typically reflect the higher than expected summer temperatures, often in conjunction with unexpected generation and transmission equipment failures.

Unexpected generation and transmission equipment failures, however, contributed to high prices in the fall of 1999. For the months of October and November of 1998, when conditions were more "average" the staff's forecast was within 1 percent. For these same months in 1999, the PX prices were dramatically higher than the staff's forecast.

The episode on September 30, 1999 serves as a vivid example of atypical conditions. The system experienced a 4,600 MW unexpected deficiency. Peak loads were 1,512 MW higher than expected. The California Oregon Intertie, which consists of three high voltage AC transmission lines connecting California with the Pacific Northwest, was derated due to the proximity of fires at Red Bluff. Diablo Canyon 2 (1100 MW) was down for refueling, and Diablo Canyon 1 was derated (from 1100 MW down to 480 MW) due to tube leaks, which in turn caused a derate of the Path 15 transmission system, which connects northern and southern California. Within one hour, the 756 MW Navajo coal plant tripped off-line. MCPs followed suit and soared.

Forecasting an accurate monthly average MCP is only half of the challenge. It is just as important to be able to forecast hourly values. Since the most important revenue can occur in the on-peak hours, it is important to know what the MCPs are on an hourly basis.

For most months, the hourly comparison is difficult since the monthly average values of the forecast differ significantly from the PX prices. There are three months, however, where the two monthly values were quite close: November and December of 1998 and August of 1999.

Figures B-1C through **B-1E** show the hourly comparison of the staff's forecast to actual PX prices for these three months.

Figure B-1C

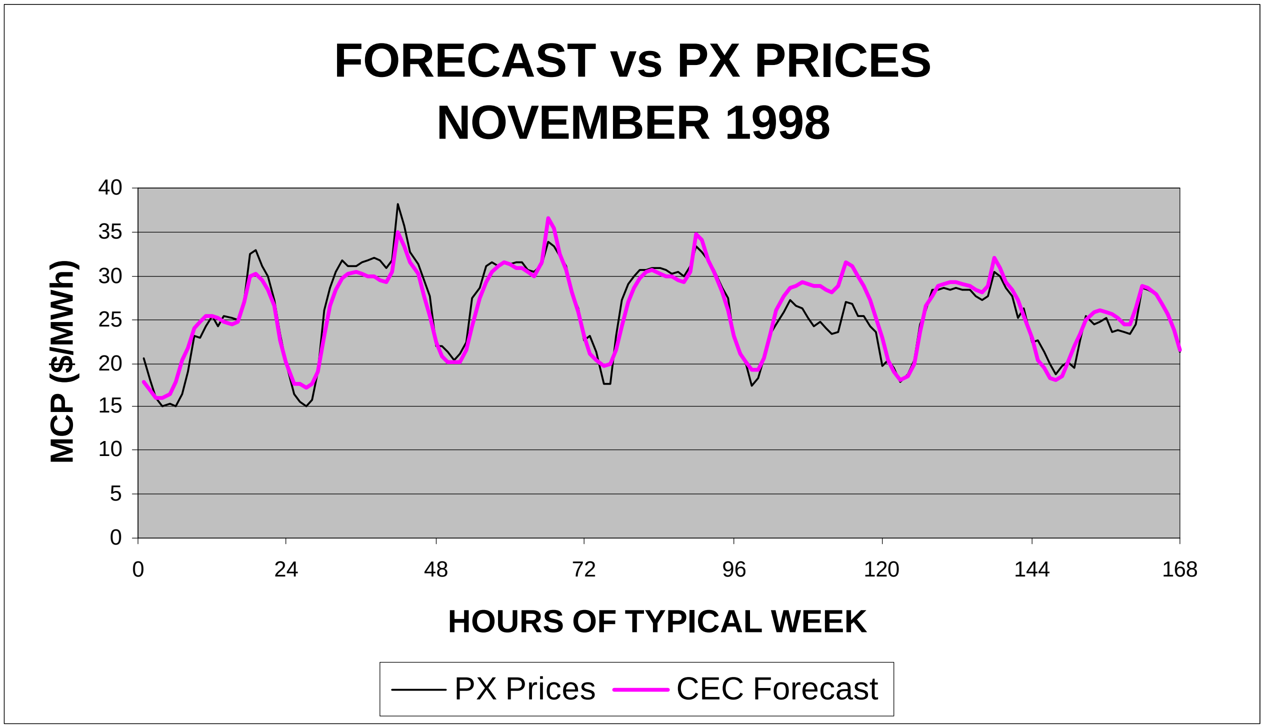


Figure B-1D

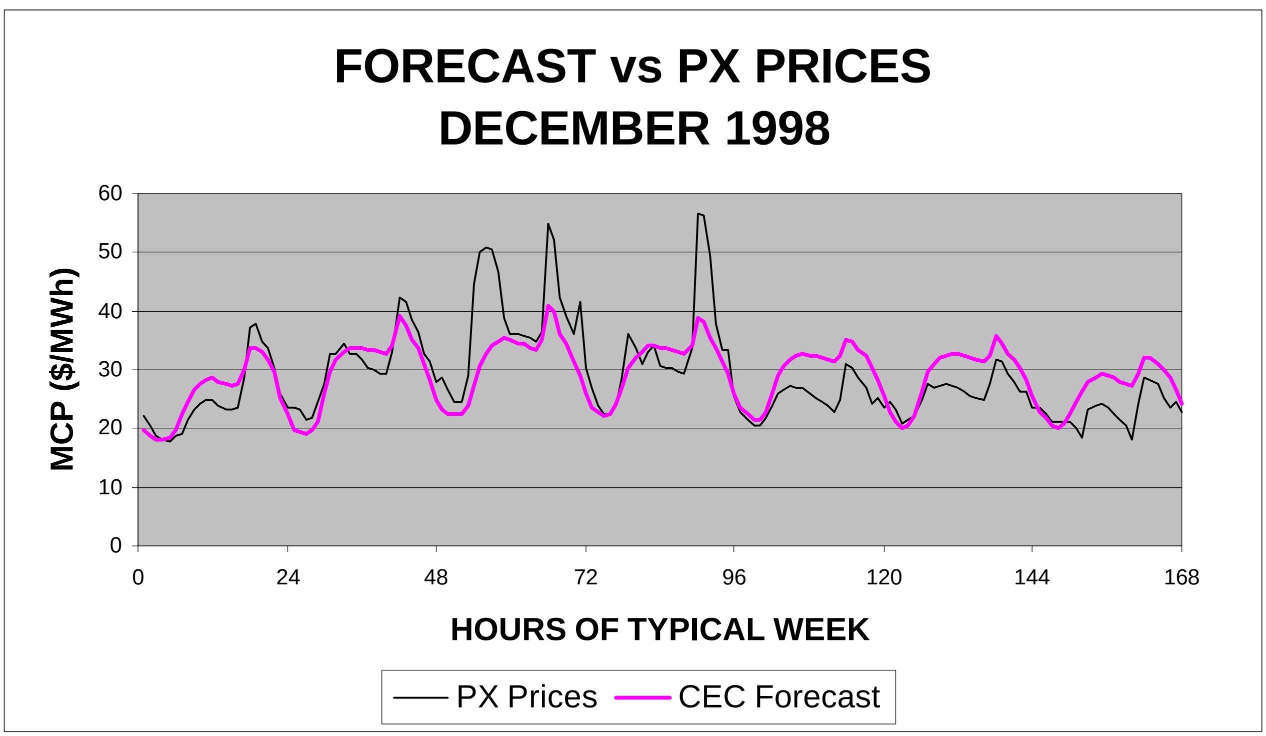
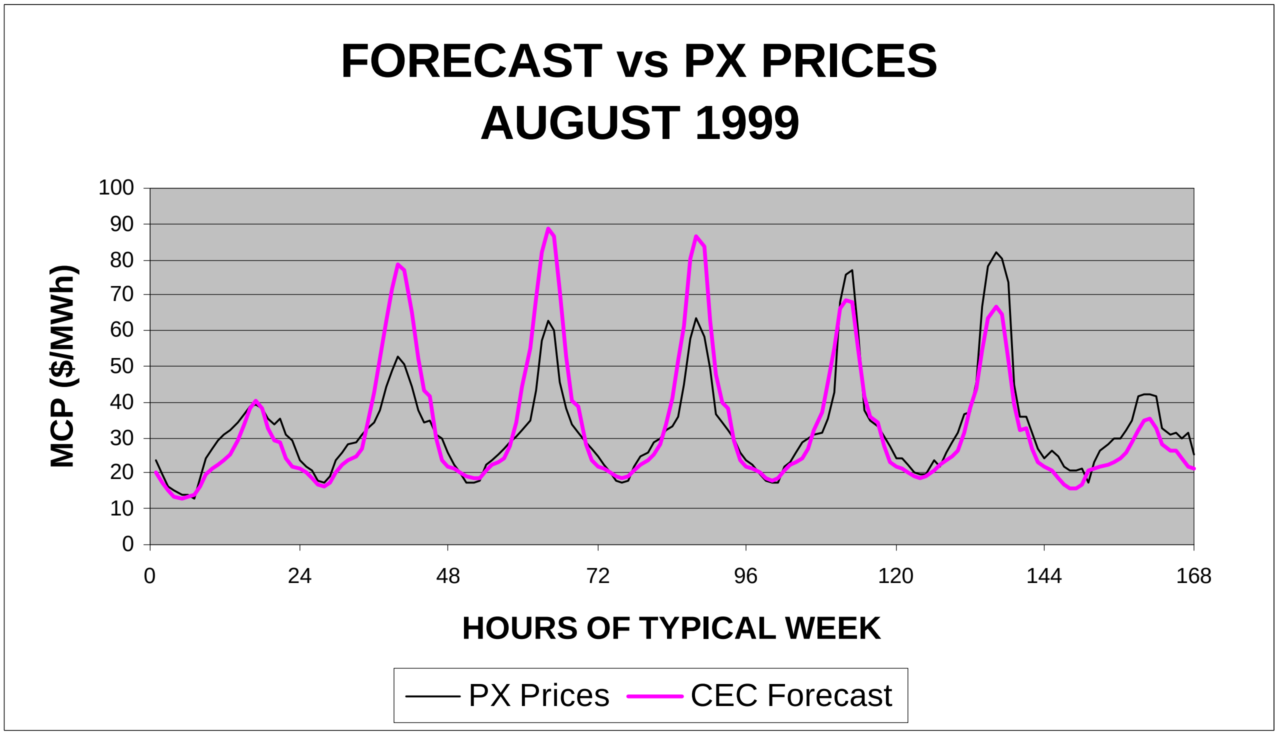


Figure B-1E



The comparison for November of 1998, **Figure B-1C**, is not significant in terms of validating the forecast, as the actual PX data were not only known at the time of the forecast, it was used in developing the shape.[ii] It does serve, however, to convey the staff's conclusion as to what constitutes an acceptable shape for this month.

The comparison for December of 1998, **Figure B-1D,** is more meaningful in terms of validating the forecast methodology as the actual PX data became available after the forecast technical work. This comparison shows that although the staff accurately predicted the monthly value, and in a most general way predicted the shape, it could not—and does not expect to be able to—capture the subtleties of market volatility.

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[i] Ibid

[ii] Ibid, Appendix D, Page 43.

The comparison for August of 1999, **Figure B-1E**, is interesting in that the forecast captured the average monthly price and general shape, but it tended to overstate the peaks for Monday, Tuesday and Wednesday. As with December of 1998, the staff does not hope to capture the unexpected volatility of the market, due to such unexpected conditions of abnormal temperature, hydro conditions, and equipment failures.

Appendix C: New Generation Additions Proposed for the WSCC Outside of California

Northwest Power Pool Additions

Facility	State	Unit Type	Fuel Type	# of Units	Capacity (MW)	Estimated Date of Operation	Company	Regulatory Approval Received	Status
Poplar Hill	Alberta		Gas	1	45	January-99	ATCO	Yes	1
Fort Saskatchewan	Alberta				120	December-99	TransAlta	Yes	1
Millennium Cogeneration Ph 1	Alberta	CC	Gas		230	December-99	TransAlta	Yes	1
Joffre	Alberta		Gas		416	September-00	CU Power	Yes	1
Taylor Coulee Shute	Alberta		Hydro		12.5	January-01	Canadian Hydro	Yes	1
Millennium Cogeneration Ph 2	Alberta	CC	Gas		130	December-01	TransAlta	Yes	2
Ft McMurray	Alberta	GT	Gas	2	172	December-02	ATCO/Shell	No	4
Fort Nelson	BC		Gas		45	April-99	BC Hydro/Trans	Yes	1
Stave Falls	BC		Hydro		38	December-00	BC Hydro	Yes	1
Island Cogeneration	BC		Gas		250		Westcoast nrg	Yes	1
Port Alberni	BC		Gas		240		CU Power	Yes	
Rathdrum	ID		Gas	1	270	September-01	Avista		
Blackfeet	MT		Gas		160	June-01	Adair	N/A	5
Carbon County	MT		Coal		2,000	December-03	Composite	No	5
Carlin County	NV				500		Coastal Power		5
Vansycle Ridge	OR	WT	Wind	38	25	March-99	Vestas	Yes	1
Klamath Falls Cogeneration	OR	CC	Gas	2	500	July-01	PacifiCorp	Yes	1
Hermiston	OR	CC	Gas	2	536	December-01	Ida Corp	Yes	2
Newberry	OR		Geothermal		30		NW Geo		
Little Sandy Dam	OR		Hydro		-11		Portland GE	N/A	1
Everett	WA		Gas		248	December-01	FPL Energy	Yes	2
Cowlitz Cogeneration project	WA	CC	Gac	2	250	February-04	Weyerhauser	Yes	2
Satsop	WA	CC	Gas	2	454		Energy Northwest	Yes	3
Sumas 2 Generating Facility	WA	CC	Gas	2	720	December-03	National Energy	Pending	3
Total MW Northwest Area					**7,380.5**				

Status Key: 1- Under construction or completed; 2- Regulatory approval received; 3- Application under review;
4- Starting app process; 5- Press release only

Southwest Power Area (Arizona, New Mexico, Southern Nevada) Additions

Facility	State	Unit Type	Fuel Type	# of Units	Capacity (MW)	Estimated Date of Operation	Company	Regulatory Approval Received	Status
South Point	AZ		Gas		500	May-01	Calpine	Yes	1
Griffith Energy Project	AZ	CC	Gas	2	520	May-01	Duke/PP&L	Yes	1
Desert Basin Generating	AZ		Gas		500	June-01	Reliant	Yes	1
43rd Ave Plant (Phase 1)	AZ	CC	Gas	1	130	August-01	APS/Calpine	Yes	2
43rd Ave Plant (Phase 2)	AZ	CC	Gas	2	500	December-01	APS/Calpine	Yes	2
Arlington Valley	AZ		Gas		500	August-02	Duke	No	5
Redhawk 1	AZ	CC	Gas	1	530	June-03	APS	No	3
Harquahala Generating Station	AZ	CC	Gas		1000	June-03	PG&E	No	3
Kyrene	AZ	CC	Gas		825	January-04	SRP/NRG		4
Gila Bend	AZ	CC	Gas	2	750	June-04	Power Dev Ent	No	5
Redhawk 2	AZ	CC	Gas	1	530	December-04	APS	No	3
Redhawk 3	AZ	CC	Gas	1	530	June-06	APS	No	3
Redhawk 4	AZ	CC	Gas	1	530	December-07	APS	No	3
Santan	AZ	CC	Gas		825		SRP	No	5
Gila River	AZ				2000	December-02	Panda Energy	No	5
El Dorado Energy Project	NV	CC	Gas	2	492	May-00	Sempra/Reliant	Yes	1
Next Generation II	NV		Gas		30	October-01	Next Generation	No	4
Nevada Green Energy Project	NV		Renew		150	December-02	Composite		5
Cobisa-Person	NM	SC	Gas	1	140	May-00	MCN Energy	Yes	1
Belen	NM		Gas		220		Cobisa	No	5
Albuquerque Solar	NM		Solar		5		PSC NM		
Total MW Southwest Area					**11,207.0**				

Status Key: 1- Under construction or completed; 2- Regulatory approval received; 3- Application under review; 4- Starting app process; 5- Press release only

Rocky Mountain Power Area Additions

Facility	State	Unit Type	Fuel Type	# of Units	Output (MW)	Estimated Date of Operation	Company	Regulatory Approval Received	Status
Brush	CO		Gas		60	June-99	BIV Generation	Yes	1
Ray D. Nixon (Phase I)	CO	GT	Gas		70	July-99	Coastal/CSU	Yes	1
CO Wind Farm	CO	WT	Wind		20	August-99	PSC CO	Yes	1
Pawnee Generation Station	CO		Gas	1	265	May-00	Fulton/Coastal	Yes	2
Front Range (Ft Lupton)	CO	CC	Gas	1	164	May-00	KN Power	Yes	2
Valmont	CO		Gas/Coal	N/A	11	December-00	New Centuries	Yes	2
Arapahoe	CO		Gas	2	100	December-00	New Centuries	Yes	2
Fort St. Vrain	CO		Gas	1	235	June-01	PSC CO		
Ray D. Nixon (Phase 2)	CO	CC	Gas		400	December-02	Coastal/CSU	Pending	3
Foote Creek	WY	WT	Wind		41	April-99	PacifiCorp	Yes	1
Arlington Wind Farm	WY	WT	Wind		25	December-00	PSC CO	Yes	2
Black Hills	WY		Coal		80		Black Hills		
Project Orion	‘Multi-state		Gas		5,000		KN Energy	No	5
Total MW Rocky Mtn. Area					**6,471**				

CFE-Mexico Northern Baja Additions

Facility	State	Unit Type	Fuel Type	# of Units	Capacity (MW)	Estimated Date of Operation	Company	Regulatory Approval Received	Status
Cerro Prieto	Mexico		Geothermal		100	July-00	CFE	Yes	1
Rosarito GT	Mexico	GT	Gas		150	July-99	CFE	Yes	1
Rosarito CC	Mexico	CC	Gas		550	July-01	CFE	Yes	1
Rosarito Baja	Mexico		Gas		450	May-02	CFE		5
Total MW CFE-Mexico					**1,250**				

Status Key: 1- Under construction or completed; 2- Regulatory approval received; 3- Application under review; 4- Starting app process; 5- Press release only

Appendix D: Overview of California Electricity Markets

The California PX Energy Markets

The California PX currently runs three markets: the day-ahead, hour-ahead, and block-forward markets. The PX day-ahead market and hour-ahead market discussed below have been operational since the kickoff of competition on April 1, 1998. Together these markets are the primary means that determine California's unconstrained competitive wholesale electricity prices.

PX Day-Ahead Market

The day-ahead market is a forward market for energy and ancillary services that allows wholesale electricity purchasers and suppliers to arrange transactions a day in advance. Advance day-ahead trading activity begins two days before trading day when the ISO publishes system loads and ancillary service requirement forecasts for the ISO-controlled grid. The ISO provides a forecast update the day before trading.

In the PX day-ahead market, participants use PX facilities to submit bids to buy and sell energy for each hour of the following day. The bidding instrument is a 15-segment linear bid curve that must be increasing in the price over the entire quantity offered. These bids are commonly called portfolio bids because they reflect consumption or output from a variety of loads or sources of electricity. Participants specify the sources of electricity later in the process. The PX verifies the bids, ensuring that bidders are capable of completing proposed transactions, then assembles the bid data to generate aggregate supply and demand curves for each hour. The intersection of these curves establishes hourly, unconstrained PX clearing prices.

After establishing the day-ahead PX clearing price, the PX assembles the details of each market participant's bids. A supplier might have particular generation plants in mind for generating, and purchasers may have loads scattered around the State. This information is provided to the PX in initial preferred schedules.[i] Initial preferred schedules are supplemented with schedule adjustment bids that indicate participants' willingness and price to increase or decrease output from a particular generator or reduce consumption.[ii] Participants that do not provide adjustment bids are price takers if any adjustments become necessary.

The PX provides the initial preferred schedules and adjustment bid information to the ISO. From the ISO perspective, the PX is one scheduling coordinator among many providing similar information. The ISO evaluates all the proposed schedules to verify that the transmission system can facilitate the transactions. If congestion occurs, the ISO uses adjustment bids to find the least cost solution to relieve the congestion.[iii] By 4:00 p.m. the day before the trading day, the PX publishes the hourly MCP and the maximum quantities of PX participants for the following day.

PX Hour-Ahead Market

The hour-ahead market provides PX market participants a means to optimize their schedules and reduce a real time imbalance. Hour-ahead market bids are submitted at least two hours before operation and include all pertinent details—that is, no portfolio bids are allowed. Bid iterations are not conducted in the hour-ahead market. The PX determines PX market-clearing schedules and provides this information to the ISO. On January 17, 1999, the PX replaced the hour-ahead market with the day-of market on an experimental basis. However, on November 10, 1999, the PX applied to the Federal Energy Regulatory Commission to make the day-of market a permanent feature. The day-of market consists of three auctions: an auction at 6:00 a.m. for operating hours ending 11:00 a.m. - 4:00 p.m., one at noon for operating hours ending 5:00 p.m. to midnight, and one at 4:00 p.m. for operating hours ending 1:00 a.m. to 10:00 a.m. Like the PX hour-ahead market, the day-of allows no portfolio bids or iterations. The day-of market was introduced because PX hour-ahead market complexity and transactions costs resulted in thin markets, characterized by wild price fluctuations.

Block-Forward Market

The PX block-forward market was introduced in July 1999 to enhance the value and flexibility of PX markets. This market has its own rules, which are enforced by PX Trading Services, a separate division of the PX. Participants in the block-forward market must also be participants in the PX day-ahead market. The block-forward market allows electricity traders to trade electricity contracts for physical delivery in either north of Path 15 (NP 15) or south of Path 15 (SP 15) up to six months in the future. Contracts traded in the block-forward market are standardized contracts for delivery of electricity during the on-peak hours of the month. Actual hours covered are 6:00 a.m. to 10:00 p.m. weekdays and Saturdays but excluding Sundays and holidays.[iv]

As with futures contracts in other commodity markets, block-forward market contracts allow electricity purchasers and suppliers to lock in prices, providing certainty, and a shelter from risk. Block-forward market participants can schedule partial or whole delivery of electricity either bilaterally or through the day-ahead market. If the delivery is scheduled through the day-ahead market, block-forward market participants can also bid electricity originally traded in the block-forward market in the day-ahead market.

ISO Imbalance Markets, Congestion Management, and Ancillary Services

The ISO ensures the reliability of the system through its imbalance market and by procuring ancillary services from generators through long-term contracts and a competitive bidding process. The imbalance market and ancillary services are intended to meet the real-time requirements of the system by balancing electricity supply and demand, maintaining transmission line voltage and facilitating electricity transfers, and providing the necessary reserve of generation capacity to cover certain contingencies.

Real-Time Imbalance Market

Actual electricity use will differ from electricity scheduled in the day-ahead and day-of markets. The ISO retains generating plants that provide backup reserves or electricity to follow small deviations from schedule.[v] For large or sustained deviations from the schedule, the ISO conducts a real-time energy market. Would be real-time market participants submit supplemental bids, which are added to a Balancing Energy *Ex-Post* Pricing (BEEP) stack. The ISO selects generators from the BEEP stack in order of economic merit to provide supplemental energy. In contrast to day-ahead and day-of energy markets, where prices are known in advance of actual market transactions, the price of real time energy may not be available until after the energy has been consumed, hence the term *ex-post* pricing.

During the transition period, the real time energy market has been subject to price caps. On October 1, 1999, the ISO raised the price cap from $250/MW to $750/MW.

Adjustment Bids for Congestion Management

Congestion occurs when unconstrained schedules submitted by scheduling coordinators require more transmission capacity than may exist in certain paths. Congestion may occur within or between congestion zones.

Interzonal Congestion

When congestion occurs between zones, the ISO seeks to reduce electricity flows over the congested path by increasing generation in the congested zone and decreasing generation in the uncongested zone. This is accomplished through adjustment bids submitted by scheduling coordinators to the ISO. The ISO selects an adequate package of the lowest cost incremental (“inc”) bids in the congested zone and the highest value decremental generation (“dec”) bids in the uncongested zone. Dispatched, loads on the congested interzonal transmission line are reduced and congestion is alleviated.

Intrazonal Congestion

Resolving congestion within zones is less simple. Location of generators on the transmission grid is paramount, and there may not be sufficient eligible generators to ensure competitive bidding. If the ISO determines that the generation market on both sides of the congested intra zonal path is workably competitive, then congestion will be relieved using competitively procured inc and dec bids, as is done with interzonal congestion. If either side of the congested path is deemed not to be workably competitive, then the ISO will resolve congestion through a RMR contract. Recent FERC decisions, however, have forced the ISO to rethink its congestion management system.

Cost Recovery

Recovery of the costs of relieving congestion is different for interzonal and intrazonal congestion. For intrazonal congestion, payments to generators that resolve congestion through bids or RMR contracts are totaled and recovered equally from all scheduling coordinators operating in the zone. In interzonal congestion, costs are recovered naturally from the market because the incremental and decremental bids set the MCP for electricity in the congested and uncongested zones, respectively. In cases of interzonal congestion, a congestion payment is made to owners of transmission facilities and firm transmission rights (FTRs). The value of the payment is the difference between the constrained MCPs in the zones on either side of the congested path, scaled to reflect the transmission or FTR owner's share and loading of the congested transmission interface during times of congestion.

Ancillary Services Bids, Day Ahead and Hour-Ahead Market

Ancillary Services are products of generating electricity that play a special role in the delivery of electric service in two ways. First, ancillary services constitute available generation capacity to replace generation lost during contingencies. Second, ancillary services constitute available generation capacity required to respond to variations in electricity demand. Ancillary services have some aspects of public goods. All electricity consumers benefit from ancillary services, but without administrative intervention, no single electricity customer would be likely to schedule and pay for adequate ancillary services.[vi] Most ancillary services support the electrified grid, but one service, black start capability, is important specifically for re-electrification of the grid after major disturbances.

The ISO procures necessary ancillary services through long term contracts and daily bidding. **Table D-1** describes the six ancillary services and the way they are procured by the ISO.

Daily Ancillary Services Bidding

The ISO uses schedules in the day-ahead energy market to determine daily ancillary services requirements. After adjusting ancillary services requirements for those being self provided by scheduling coordinators, the ISO puts ancillary services out to bid. Active scheduling coordinators that wish to compete in the daily ancillary services market may provide terms to the ISO when they submit requests for transmission capacity after the day-ahead energy market closes. The ISO selects the package of ancillary services that satisfy system requirements at the least cost. A similar process is employed for adjusting ancillary services for the day-of market. Ancillary services procured through daily bidding are subject to the same price cap applied to energy prices. As with energy prices, ancillary services prices may fluctuate wildly depending on the need for particular services. **Table D-2** shows the relative costs of the various ancillary services that are traded on a daily basis.

A scheduling coordinator may opt to self provide a part or all of the ancillary services associated with its load rather than rely on ISO procurement. This information would be indicated with schedules submitted in the day-ahead energy market. A scheduling coordinator may save money if its costs are less than the market price charged by the ISO.

Ancillary Services Revenue - Potential Cost Recovery

As a general policy, the ISO charges scheduling coordinators for the ancillary services procured to secure their load. Charges are typically calculated on a trading interval basis by congestion zone. Generators that self-provide some or all of their ancillary services are relieved of their community obligations to ancillary services costs to the extent of their self-provision. There is some variation in calculation of a scheduling coordinator's specific ancillary services' charge due to the nature of some services. Costs of *ex-post* real time energy are included with the ancillary services charge.

TABLE D-1
List of Ancillary Services

Service	Description	How Procured, Paid & Charged
Voltage Support/ Reactive Power	Electricity injections at specific areas in the transmission grid for maintaining reactive capacity and voltage requirements.[vii] The site-sensitive nature of this service may limit competition due to lack of contestants.	**Procured:** Contract (“Voltage Support Agreement”) monthly and real time supplemental on *ex post* basis[viii] **Paid:** $ MW, settled on monthly basis. For *ex post* supplemental, by congestion zone and trading interval **Charged:** By congestion zone and trading interval. Scheduling coordinator’s share of total cost.
Black Start	Restoration of electricity to the ISO-controlled grid by providing the ability to self-start without an external source of electricity.	**Procured:** Contract (“Black Start Agreement”) **Paid:** Contract price in $ MW multiplied by monthly output of black start energy by trading interval and congestion zone. **CHARGED:** Scheduling coordinator’s share of metered demand in trading interval and congestion zone in which service is needed, including costs of testing black start capability.
Regulation/ Frequency	Generation plants equipped with Automated Generation Control (AGC) may be adjusted remotely by the ISO to maintain system frequency and tieline loading within NERC and WSCC operating criteria.	**Procured:** Daily Bidding **Paid:** $/MW, market-clearing price **Charged:** By congestion zone and trading interval. scheduling coordinator’s share of total spin cost by trading interval and congestion zone, minus amount self provided.
Spinning Reserve	Unloaded but spinning (synchronized) generation capacity that is able to be immediately responsive to system frequency and capable of being loaded within ten minutes and holding the load for at least two hours.	**Procured:** Daily Bidding **Paid:** $/MW, market-clearing price **Charged:** by congestion zone and trading interval Subject to Individual Generator Price Ceiling, scheduling coordinator’s share of total Spin cost by trading interval and congestion zone, minus amount
Non-Spinning Reserve	Off-line generating capacity that can synchronize and take load in ten minutes. “Non-spin” has a demand-side equivalent, which is load that can be interrupted in ten minutes. Non-spin generators and load must be capable of providing the service for at least two hours.	**Procured:** Daily Bidding **Paid:** $/MW, market-clearing price **Charged:** By congestion zone and trading interval. scheduling coordinator’s share of total nonspin cost by trading interval and congestion zone, minus amount self provided.
Replacement Reserve	Generation capacity capable of synchronizing to the grid and taking a certain load within sixty minutes of notification and running for two hours, which is set aside to replace energy and ancillary services reserves that have been dispatched. This service may also be provided by load that will curtail within sixty minutes for a period of two hours. Replacement reserve typically makes up for scheduled generation that becomes unavailable.	**Procured:** Daily Bidding **Paid:** $/MW **Charged:** Two components. 1) Actual cost of dispatched replacement reserves billed to each scheduling coordinator in proportion of its imbalance energy as share of total imbalance energy 2) Undispatched replacement reserve billed to all scheduling coordinators in proportion to their respective shares of total cost by trading interval and congestion zone.

Table D-2
Ancillary Service Cost As A Percent of Total A/S Costs

Month	Regulation	Regulation Down	Regulation Up	Spinning Reserves	Non-spinning Reserves	Replacement Reserves
Dec-98	69%			26%	4%	1%
Jan-99	89%			9%	1%	1%
Feb-99	87%			10%	2%	1%
Mar-99	88%			10%	1%	1%
Apr-99	81%			15%	2%	2%
May-99	85%			9%	5%	1%
Jun-99		43%	44%	8%	5%	1%
Jul-99		27%	41%	13%	12%	6%
Aug-99		21%	42%	16%	14%	7%
Sep-99		32%	34%	17%	10%	8%
Oct-99		25%	40%	16%	9%	11%
Nov-99		56%	30%	9%	4%	1%

Source: California ISO

[i] In some cases, preferred generator dispatch schedules may not be a matter only of preference. Physical design of a package of generating plants may preclude them from operating or responding to operational commands individually.

[ii]At this point, suppliers and purchasers also include any bids to supply ancillary services.

[iii] See discussion of congestion below.

[iv]A minimum contract unit is for delivery of a one MW of energy for sixteen hours a day during a month. This translates into either 400 or 416 MWh/month (16 hrs* 25 days or 26 days = 400 MWh or 416 MWh).

[v] See Replacement Reserves and Automated Generation Control below. Major or sustained deviations from schedule may be substantial enough that these plants cannot compensate without compromising regulating margins, necessitating an additional market to compensate for these larger deviations from schedule.

[vi] In this context, “adequate” means within standards set by the WSCC.

[vii] Transmission system equipment—such as shunt capacitors, can sometimes be used to maintain voltage and reactive power; however, in some cases, the use of non-generation equipment is impractical or cost-prohibitive.

[viii] Expected software enhancements will eventually allow other generators to compete to provide these services.